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July 19, 2004

VIA HAND DELIVERY

Vance Broemel
Tim Phillips
Office of Attorney General
Consumer Advocate and Protection Division
2nd Floor
425 5th Avenue North
Nashville, TN 37243-0491

Re: Petition of Chattanooga Gas Company for Approval of Adjustment of its Rates and Charges and Revised Tariff
Docket Number 04-00034
Responses to Discovery Requests from the Consumer Advocate and Protection Division

Dear Vance and Tim:

Enclosed you will find responses to the additional discovery requests to which Chattanooga Gas Company was directed to respond pursuant to the Hearing Officer's Order, dated July 12, 2004.

Sincerely,

D. Billye Sanders

D. Billye Sanders
Attorney for Chattanooga Gas Company

DBS/hmd

1035564 1

cc: Parties of Record
Tennessee Regulatory Authority
Archie Hickerson
Steve Lindsey
John Ebert, Esq.
Elizabeth Wade, Esq.

CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of July 2004, a true and correct copy of the foregoing document was delivered by hand delivery, email or U.S. mail postage prepaid to the other Counsel of Record listed below.

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Discovery Request No. 12:

On page 11 of Mr. Morley's testimony he states, "The increase in distribution expenses is due to a Federal Energy regulatory Commission ("FERC") mandated pipeline integrity program."

(a) Provide copies of all supporting documents (any FERC Order, law, or other requirement) specifically "<u>mandating</u>" the pipeline integrity program and
(b) explain the impact on state regulatory authorities

Response:

(a) The reference to the Federal Energy Regulatory Commission in Mr. Morley's testimony should have been to the U.S. Department of Transportation. Attached are copies of the Pipeline Safety Act of 2002 (attachment bb) and the 49 CFR Part 192 (Subpart O of the Pipeline Safety Regulations) as published by the U.S. Department of Transportation (attachment aa).
(b) Under Tennessee Law natural gas operations under the jurisdiction of the Tennessee Regulatory Authority are required to follow the federal safety standards. *See* T.C.A. § 65-28-105 and § 65-28-106.

Electronic Code of Federal Regulations (e-CFR)

BETA TEST SITE

e-CFR Data is current as of April 23, 2004

Title 49: Transportation

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Browse Previous

Subpart O—Pipeline Integrity Management

Source: 69 FR 69817, Dec. 15, 2003, unless otherwise noted.

§ 192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.

§ 192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (*i.e.*, external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact radius contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph

(4) applies; or

(ii) An identified site.

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d 2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

Note:

0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S–2001 (Supplement to ASME B31.8; ibr, see §192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (*e.g.*, a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

§ 192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (ibr, *see* §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

§ 192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (ibr, *see* §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of §192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.

(j) Record keeping provisions meeting the requirements of §192.947.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (*See* §192.905 and §192.921.)

§ 192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (ibr, *see* §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

(ii) All risk factor data used to support the program;

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in §192.945 that are part of the operator's performance plan. (*See* §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (*e.g.*, confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (ibr, see §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment,

an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18231, Apr. 6, 2004]

§ 192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* §192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

(b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) ASME/ANSI B31.8S (ibr, *see* §192.7), section 6.4; NACE RP0502–2002 (ibr, *see* §192.7); and §192.925 if addressing external corrosion (ECDA).

(2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and §192.927 if addressing internal corrosion (ICDA).

(3) ASME/ANSI B31.8S, appendix A3, and §192.929 if addressing stress corrosion cracking (SCCDA).

(c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

§ 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, *see* §192.7), section 6.4, and NACE RP 0502–2002 (ibr, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect inspections, direct examination, and post-assessment.

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in appendix A of NACE RP0502–2002, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect Examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either (a) corrosion defects are discovered that exceed allowable limits (section 5.5.2.2 of NACE RP0502–2002), or

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (ibr, see §192.7), section 6.4, and in NACE RP 0502–2002 (ibr, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (ibr, see §192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §192.921 (a)(4) or §192.937 (c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment.* In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (*See* paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification.* An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02–0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (ibr, *see* §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02–0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.*, sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (*e.g.*, ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18232, Apr. 6, 2004]

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (ibr, *see* §192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) *Assessment method.* The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§ 192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§192.925 (ECDA) and §192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE RP 0502–2002 (ibr, *see* §192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (ibr, *see* §192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG"; ibr, *see* §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (*See* appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with §192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(d) *Special requirements for scheduling remediation.*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage.* If an operator determines that outside force (*e g.*, earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2)of this section, the requirements for a low stress external corrosion reassessment in §192.941(b) and the requirements for a low stress internal corrosion reassessment in §192.941(c). An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004]

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (ibr, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology.* An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP0502–2002 (ibr, *see* §192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for

Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

	Maximum Reassessment Interval	
Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating or above 30% SMYS, to 50% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)...........	15 years (*)........
Confirmatory Direct Assessment.......	7 years................	7 years.............
Low Stress Reassessment..............	Not applicable.........	Not applicable......

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted b interval.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (*i e.* indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe, where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and

(ii) Every eighteen months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)–(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply.* An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.945 What methods must an operator use to measure program effectiveness?

(a) *General.* An operator must include in its integrity management program methods to measure, on a semi-annual basis, whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (ibr, see §192.7), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At maximum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;

(c) A written baseline assessment plan in accordance with §192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;

(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

[69 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

§ 192.949 How does an operator notify OPS?

An operator must provide any notification required by this subpart by—

(1) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street, SW., Washington, DC 20590;

(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128; or

(3) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp/.*

§ 192.951 Where does an operator file a report?

An operator must send any performance report required by this subpart to the Information Resources Manager—

(1) By mail to the Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Washington, DC 20590;

(2) Via facsimile to (202) 366–7128; or

(3) Through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at *http://ops.dot.gov*

Appendix A to Part 192—Incorporated by Reference

I. List of Organizations and Addresses

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.

G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. 9101, Quincy, MA 02269–9101.

II. Documents Incorporated by Reference (Numbers in Parentheses Indicate Applicable Editions)

A. American Gas Association (AGA):

(1). AGA Pipeline Research Committee, Project PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989).

B. American Petroleum Institute (API):

(1) API Specification 5L "Specification for Line Pipe (41st edition, 1995).

(2). API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).

(3) API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).

(4) API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).

C. American Society for Testing and Materials (ASTM):

(1) ASTM Designation: A 53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53–96).

(2) ASTM Designation A 106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106–95).

(3) ASTM Designation: A 333/A 333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A 333/A 333M–94).

(4) ASTM Designation: A 372/A 372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A 372/A 372M–95).

(5) ASTM Designation: A 381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems (A 381–93).

(6) ASTM Designation: A 671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A 671–94).

(7) ASTM Designation: A 672 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A 672–94).

(8) ASTM Designation A 691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High- Pressure Service at High Temperatures" (A 691–93).

(9) ASTM Designation D638 "Standard Test Method for Tensile Properties of

Plastics" (D638–96).

(10) ASTM Designation D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing and Fittings" (D 2513–87 edition for §192.63(a)(1), otherwise D 2513–96a).

(11) ASTM Designation D 2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D 2517–94).

(12) ASTM Designation: F1055 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (F1055–95).

D. The American Society of Mechanical Engineers (ASME):

(1) ASME/ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1989).

(2) ASME/ANSI B16.5 "Pipe Flanges and Flanged Fittings" (1988 with October 1988 Errata and ASME/ANSI B16.5a–1992 Addenda).

(3) ASME/ANSI B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" (1991).

(4) ASME/ANSI B31.8 "Gas Transmission and Distribution Piping Systems" (1995).

(5) ASME Boiler and Pressure Vessel Code, Section I "Power Boilers" (1995 edition with 1995 Addenda).

(6) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 "Pressure Vessels" (1995 edition with 1995 Addenda).

(7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Pressure Vessels: Alternative Rules" (1995 edition with 1995 Addenda).

(8) ASME Boiler and Pressure Vessel Code, Section IX "Welding and Brazing Qualifications" (1995 edition with 1995 Addenda).

(9) ASME/ANSI B31.8S–2001 (Supplement to B31.8), "Managing System Integrity of Gas Pipelines," July 19, 2002.

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):

1. MSS SP44–96 "Steel Pipe Line Flanges" (includes 1996 errata) (1996).

2. [Reserved]

F. NACE International

(1) NACE RP–0502–2002 "Pipeline External Corrosion Direct Assessment Methodology," 2002.

H. National Fire Protection Association (NFPA):

(1) NFPA 30 "Flammable and Combustible Liquids Code" (1996).

(2) ANSI/NFPA 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1995).

(3) ANSI/NFPA 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1995).

(4) ANSI/NFPA 70 "National Electrical Code" (1996).

I. Gas Research Institute

(1) GRI 02–0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," April 1, 2002.

[58 FR 14521, Mar. 18, 1993, as amended by Amdt. 192–68, 58 FR 45268–45269, Aug. 27, 1993; Amdt. 192–76, 61 FR 26123, May 24, 1996; Amdt. 192–78, 61 FR 28786, June 6, 1996; 61 FR 41020, Aug. 7, 1996; Amdt 192–83, 63 FR 7723, Feb. 17, 1998; Amdt. 192–84, 63 FR 38758, July 20, 1998; 69 FR 69827, Dec. 15, 2003; Amdt. 192–95, 69 FR 18234, Apr. 9, 2004]

Appendix B to Part 192—Qualification of Pipe

I. *Listed Pipe Specifications (Numbers in Parentheses Indicate Applicable Editions)*

API 5L—Steel pipe (1995). ASTM A 53—Steel pipe (1995a). ASTM A 106—Steel pipe (1994a). ASTM A 333/A 333M—Steel pipe (1994). ASTM A 381—Steel pipe (1993). ASTM A 671—Steel pipe (1994). ASTM A 672—Steel pipe (1994). ASTM A 691—Steel pipe (1993). ASTM D 2513—Thermoplastic pipe and tubing (1995c). ASTM D 2517—Thermosetting plastic pipe and tubing (1994).

II. *Steel pipe of unknown or unlisted specification*

A. *Bending Properties.* For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II–D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L. All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests_All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[35 FR 13257, Aug. 19, 1970]

Editorial Note: For Federal Register citations affecting appendix B of part 192, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

Appendix C to Part 192—Qualification of Welders for Low Stress Level Pipe

I. *Basic test.* The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192–85, 63 FR 37504, July 13, 1998]

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection*— A. *Steel, cast iron, and ductile iron structures.* (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures.* (1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections

III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated cooper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride half cell used in sea water: −0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192–4, 36 FR 12305, June 30, 1971]

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use method (a) or (b) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to figure E.I.A for a diagram of a high consequence area).

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

(a) Table E.II.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30% SMYS not in an HCA (*i.e.* outside of potential impact circle) but located within a Class 3 or Class 4 Location.

(b) Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.

(c) Table E.II.3 gives guidance on preventative & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

[Amdt. 192–95, 69 FR 18234, Apr. 6, 2004]

Browse Previous

CAPO # 12
Attachment bb

Public Law 107–355
107th Congress

An Act

To amend title 49, United States Code, to enhance the security and safety of pipelines.

Dec. 17, 2002
[H R 3609]

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Pipeline Safety Improvement Act of 2002

SECTION 1. SHORT TITLE; AMENDMENT OF TITLE 49, UNITED STATES CODE.

(a) SHORT TITLE.—This Act may be cited as the "Pipeline Safety Improvement Act of 2002". 49 USC 60101 note

(b) AMENDMENT OF TITLE 49, UNITED STATES CODE.—Except as otherwise expressly provided, whenever in this Act an amendment or repeal is expressed in terms of an amendment to, or a repeal of, a section or other provision, the reference shall be considered to be made to a section or other provision of title 49, United States Code.

SEC. 2. ONE-CALL NOTIFICATION PROGRAMS.

(a) MINIMUM STANDARDS.—Section 6103 is amended—

(1) in subsection (a)—

(A) in paragraph (1) by inserting ", including all government operators" before the semicolon at the end; and

(B) in paragraph (2) by inserting ", including all government and contract excavators" before the semicolon at the end; and

(2) in subsection (c) by striking "provide for" and inserting "provide for and document".

(b) COMPLIANCE WITH MINIMUM STANDARDS.—Section 6104(d) is amended by striking "Within 3 years after the date of the enactment of this chapter, the Secretary shall begin to" and inserting "The Secretary shall".

(c) IMPLEMENTATION OF BEST PRACTICES GUIDELINES.—

(1) IN GENERAL.—Section 6105 is amended to read as follows:

"§ 6105. Implementation of best practices guidelines

"(a) ADOPTION OF BEST PRACTICES.—The Secretary of Transportation shall encourage States, operators of one-call notification programs, excavators (including all government and contract excavators), and underground facility operators to adopt and implement practices identified in the best practices report entitled 'Common Ground', as periodically updated.

"(b) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to and participate in programs sponsored by a non-profit organization specifically established for the purpose of reducing construction-related damage to underground facilities.

"(c) GRANTS.—

"(1) IN GENERAL.—The Secretary may make grants to a non-profit organization described in subsection (b).

"(2) AUTHORIZATION OF APPROPRIATIONS.—In addition to amounts authorized under section 6107, there is authorized to be appropriated for making grants under this subsection $500,000 for each of fiscal years 2003 through 2006. Such sums shall remain available until expended.

"(3) GENERAL REVENUE FUNDING.—Any sums appropriated under this subsection shall be derived from general revenues and may not be derived from amounts collected under section 60301.".

(2) CONFORMING AMENDMENT.—The analysis for chapter 61 is amended by striking the item relating to section 6105 and inserting the following:

"6105 Implementation of best practices guidelines.".

(d) AUTHORIZATION OF APPROPRIATIONS.—

(1) FOR GRANTS FOR STATES.—Section 6107(a) is amended by striking "$1,000,000 for fiscal year 2000" and all that follows before the period at the end of the first sentence and inserting "$1,000,000 for each of fiscal years 2003 through 2006".

(2) FOR ADMINISTRATION.—Section 6107(b) is amended by striking "for fiscal years 1999, 2000, and 2001" and inserting "for fiscal years 2003 through 2006".

SEC. 3. ONE-CALL NOTIFICATION OF PIPELINE OPERATORS.

(a) LIMITATION ON PREEMPTION.—Section 60104(c) is amended by adding at the end the following: "Notwithstanding the preceding sentence, a State authority may enforce a requirement of a one-call notification program of the State if the program meets the requirements for one-call notification programs under this chapter or chapter 61.".

(b) MINIMUM REQUIREMENTS.—Section 60114(a)(2) is amended by inserting ", including a government employee or contractor," after "person".

(c) CRIMINAL PENALTIES.—Section 60123(d) is amended—

(1) in the matter preceding paragraph (1) by striking "knowingly and willfully";

(2) in paragraph (1) by inserting "knowingly and willfully" before "engages";

(3) by striking paragraph (2)(B) and inserting the following:

"(B) a pipeline facility, and knows or has reason to know of the damage, but does not report the damage promptly to the operator of the pipeline facility and to other appropriate authorities; or"; and

(4) by adding after paragraph (2) the following:

"Penalties under this subsection may be reduced in the case of a violation that is promptly reported by the violator.".

SEC. 4. STATE OVERSIGHT ROLE.

(a) STATE AGREEMENTS WITH CERTIFICATION.—Section 60106 is amended—

(1) in subsection (a) by striking "GENERAL AUTHORITY.—" and inserting "AGREEMENTS WITHOUT CERTIFICATION.—";

(2) by redesignating subsections (b), (c), and (d) as subsections (c), (d), and (e), respectively; and

(3) by inserting after subsection (a) the following:

"(b) AGREEMENTS WITH CERTIFICATION.—

"(1) IN GENERAL.—If the Secretary accepts a certification under section 60105 and makes the determination required under this subsection, the Secretary may make an agreement with a State authority authorizing it to participate in the oversight of interstate pipeline transportation. Each such agreement shall include a plan for the State authority to participate in special investigations involving incidents or new construction and allow the State authority to participate in other activities overseeing interstate pipeline transportation or to assume additional inspection or investigatory duties. Nothing in this section modifies section 60104(c) or authorizes the Secretary to delegate the enforcement of safety standards for interstate pipeline facilities prescribed under this chapter to a State authority.

"(2) DETERMINATIONS REQUIRED.—The Secretary may not enter into an agreement under this subsection, unless the Secretary determines in writing that—

"(A) the agreement allowing participation of the State authority is consistent with the Secretary's program for inspection and consistent with the safety policies and provisions provided under this chapter;

"(B) the interstate participation agreement would not adversely affect the oversight responsibilities of intrastate pipeline transportation by the State authority;

"(C) the State is carrying out a program demonstrated to promote preparedness and risk prevention activities that enable communities to live safely with pipelines;

"(D) the State meets the minimum standards for State one-call notification set forth in chapter 61; and

"(E) the actions planned under the agreement would not impede interstate commerce or jeopardize public safety.

"(3) EXISTING AGREEMENTS.—If requested by the State authority, the Secretary shall authorize a State authority which had an interstate agreement in effect after January 31, 1999, to oversee interstate pipeline transportation pursuant to the terms of that agreement until the Secretary determines that the State meets the requirements of paragraph (2) and executes a new agreement, or until December 31, 2003, whichever is sooner. Nothing in this paragraph shall prevent the Secretary, after affording the State notice, hearing, and an opportunity to correct any alleged deficiencies, from terminating an agreement that was in effect before enactment of the Pipeline Safety Improvement Act of 2002 if—

"(A) the State authority fails to comply with the terms of the agreement;

"(B) implementation of the agreement has resulted in a gap in the oversight responsibilities of intrastate pipeline transportation by the State authority; or

"(C) continued participation by the State authority in the oversight of interstate pipeline transportation has had an adverse impact on pipeline safety.".

(b) ENDING AGREEMENTS.—Subsection (e) of section 60106 (as redesignated by subsection (a)(2) of this section) is amended to read as follows:

"(e) ENDING AGREEMENTS.—

"(1) PERMISSIVE TERMINATION.—The Secretary may end an agreement under this section when the Secretary finds that the State authority has not complied with any provision of the agreement.

"(2) MANDATORY TERMINATION OF AGREEMENT.—The Secretary shall end an agreement for the oversight of interstate pipeline transportation if the Secretary finds that—

"(A) implementation of such agreement has resulted in a gap in the oversight responsibilities of intrastate pipeline transportation by the State authority;

"(B) the State actions under the agreement have failed to meet the requirements under subsection (b); or

"(C) continued participation by the State authority in the oversight of interstate pipeline transportation would not promote pipeline safety.

Notice

"(3) PROCEDURAL REQUIREMENTS.—The Secretary shall give notice and an opportunity for a hearing to a State authority before ending an agreement under this section. The Secretary may provide a State an opportunity to correct any deficiencies before ending an agreement. The finding and decision to end the agreement shall be published in the Federal Register and may not become effective for at least 15 days after the date of publication unless the Secretary finds that continuation of an agreement poses an imminent hazard.".

Federal Register, publication.

(c) SECRETARY'S RESPONSE TO STATE NOTICES OF VIOLATIONS.—Subsection (c) of section 60106 (as redesignated by subsection (a)(2) of this section) is amended—

(1) by striking "Each agreement" and inserting the following:

"(1) IN GENERAL.—Each agreement";

(2) by adding at the end the following:

Deadline

"(2) RESPONSE BY SECRETARY.—If a State authority notifies the Secretary under paragraph (1) of a violation or probable violation of an applicable safety standard, the Secretary, not later than 60 days after the date of receipt of the notification, shall—

"(A) issue an order under section 60118(b) or take other appropriate enforcement actions to ensure compliance with this chapter; or

"(B) provide the State authority with a written explanation as to why the Secretary has determined not to take such actions."; and

(3) by aligning the text of paragraph (1) (as designated by this subsection) with paragraph (2) (as added by this subsection).

SEC. 5. PUBLIC EDUCATION PROGRAMS.

Section 60116 is amended to read as follows:

"§ 60116. Public education programs

"(a) IN GENERAL.—Each owner or operator of a gas or hazardous liquid pipeline facility shall carry out a continuing program to educate the public on the use of a one-call notification system prior to excavation and other damage prevention activities, the possible hazards associated with unintended releases from the pipeline facility, the physical indications that such a release may have occurred, what steps should be taken for public safety in the event of a pipeline release, and how to report such an event.

"(b) MODIFICATION OF EXISTING PROGRAMS.—Not later than 12 months after the date of enactment of the Pipeline Safety Improvement Act of 2002, each owner or operator of a gas or hazardous liquid pipeline facility shall review its existing public education program for effectiveness and modify the program as necessary. The completed program shall include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. The completed program shall be submitted to the Secretary or, in the case of an intrastate pipeline facility operator, the appropriate State agency, and shall be periodically reviewed by the Secretary or, in the case of an intrastate pipeline facility operator, the appropriate State agency. Deadline.

"(c) STANDARDS.—The Secretary may issue standards prescribing the elements of an effective public education program. The Secretary may also develop material for use in the program.".

SEC. 6. PROTECTION OF EMPLOYEES PROVIDING PIPELINE SAFETY INFORMATION.

(a) IN GENERAL.—Chapter 601 is amended by adding at the end the following:

"§ 60129. Protection of employees providing pipeline safety information

"(a) DISCRIMINATION AGAINST EMPLOYEE.—

"(1) IN GENERAL.—No employer may discharge any employee or otherwise discriminate against any employee with respect to his compensation, terms, conditions, or privileges of employment because the employee (or any person acting pursuant to a request of the employee)—

"(A) provided, caused to be provided, or is about to provide or cause to be provided, to the employer or the Federal Government information relating to any violation or alleged violation of any order, regulation, or standard under this chapter or any other Federal law relating to pipeline safety;

"(B) refused to engage in any practice made unlawful by this chapter or any other Federal law relating to pipeline safety, if the employee has identified the alleged illegality to the employer;

"(C) provided, caused to be provided, or is about to provide or cause to be provided, testimony before Congress or at any Federal or State proceeding regarding any provision (or proposed provision) of this chapter or any other Federal law relating to pipeline safety;

"(D) commenced, caused to be commenced, or is about to commence or cause to be commenced a proceeding under this chapter or any other Federal law relating to pipeline safety, or a proceeding for the administration or enforcement of any requirement imposed under this chapter or any other Federal law relating to pipeline safety;

"(E) provided, caused to be provided, or is about to provide or cause to be provided, testimony in any proceeding described in subparagraph (D); or

"(F) assisted or participated or is about to assist or participate in any manner in such a proceeding or in any other manner in such a proceeding or in any other action to carry out the purposes of this chapter or any other Federal law relating to pipeline safety.

"(2) EMPLOYER DEFINED.—In this section, the term 'employer' means—

"(A) a person owning or operating a pipeline facility; or

"(B) a contractor or subcontractor of such a person.

Deadlines

"(b) DEPARTMENT OF LABOR COMPLAINT PROCEDURE.—

"(1) FILING AND NOTIFICATION.—A person who believes that he or she has been discharged or otherwise discriminated against by any person in violation of subsection (a) may, not later than 180 days after the date on which such violation occurs, file (or have any person file on his or her behalf) a complaint with the Secretary of Labor alleging such discharge or discrimination. Upon receipt of such a complaint, the Secretary of Labor shall notify, in writing, the person or persons named in the complaint and the Secretary of Transportation of the filing of the complaint, of the allegations contained in the complaint, of the substance of evidence supporting the complaint, and of the opportunities that will be afforded to such person or persons under paragraph (2).

"(2) INVESTIGATION; PRELIMINARY ORDER.—

Notification.

"(A) IN GENERAL.—Not later than 60 days after the date of receipt of a complaint filed under paragraph (1) and after affording the person or persons named in the complaint an opportunity to submit to the Secretary of Labor a written response to the complaint and an opportunity to meet with a representative of the Secretary of Labor to present statements from witnesses, the Secretary of Labor shall conduct an investigation and determine whether there is reasonable cause to believe that the complaint has merit and notify in writing the complainant and the person or persons alleged to have committed a violation of subsection (a) of the Secretary of Labor's findings. If the Secretary of Labor concludes that there is reasonable cause to believe that a violation of subsection (a) has occurred, the Secretary of Labor shall include with the Secretary of Labor's findings with a preliminary order providing the relief prescribed by paragraph (3)(B). Not later than 60 days after the date of notification of findings under this subparagraph, any person alleged to have committed a violation or the complainant may file objections to the findings or preliminary order, or both, and request a hearing on the record. The filing of such objections shall not operate to stay any reinstatement remedy contained in the preliminary order. Such hearings shall be conducted expeditiously. If a hearing is not requested in such 60-day period, the preliminary order shall be deemed a final order that is not subject to judicial review.

"(B) REQUIREMENTS.—

"(i) REQUIRED SHOWING BY COMPLAINANT.—The Secretary of Labor shall dismiss a complaint filed under this subsection and shall not conduct an investigation otherwise required under subparagraph (A) unless the complainant makes a prima facie showing that any behavior described in subsection (a) was a contributing factor in the unfavorable personnel action alleged in the complaint.

"(ii) SHOWING BY EMPLOYER.—Notwithstanding a finding by the Secretary of Labor that the complainant has made the showing required under clause (i), no investigation otherwise required under subparagraph (A) shall be conducted if the employer demonstrates, by clear and convincing evidence, that the employer would have taken the same unfavorable personnel action in the absence of that behavior.

"(iii) CRITERIA FOR DETERMINATION BY SECRETARY.—The Secretary of Labor may determine that a violation of subsection (a) has occurred only if the complainant demonstrates that any behavior described in subsection (a) was a contributing factor in the unfavorable personnel action alleged in the complaint.

"(iv) PROHIBITION.—Relief may not be ordered under subparagraph (A) if the employer demonstrates by clear and convincing evidence that the employer would have taken the same unfavorable personnel action in the absence of that behavior.

"(3) FINAL ORDER.—

"(A) DEADLINE FOR ISSUANCE; SETTLEMENT AGREEMENTS.—Not later than 90 days after the date of conclusion of a hearing under paragraph (2), the Secretary of Labor shall issue a final order providing the relief prescribed by this paragraph or denying the complaint. At any time before issuance of a final order, a proceeding under this subsection may be terminated on the basis of a settlement agreement entered into by the Secretary of Labor, the complainant, and the person or persons alleged to have committed the violation.

"(B) REMEDY.—If, in response to a complaint filed under paragraph (1), the Secretary of Labor determines that a violation of subsection (a) has occurred, the Secretary of Labor shall order the person or persons who committed such violation to—

"(i) take affirmative action to abate the violation;

"(ii) reinstate the complainant to his or her former position together with the compensation (including back pay) and restore the terms, conditions, and privileges associated with his or her employment; and

"(iii) provide compensatory damages to the complainant.

If such an order is issued under this paragraph, the Secretary of Labor, at the request of the complainant, shall assess against the person or persons against whom the order is issued a sum equal to the aggregate amount of all costs and expenses (including attorney's and expert witness fees) reasonably incurred, as determined by the Secretary of Labor, by the complainant for, or in connection with, the bringing the complaint upon which the order was issued.

"(C) FRIVOLOUS COMPLAINTS.—If the Secretary of Labor finds that a complaint under paragraph (1) is frivolous or has been brought in bad faith, the Secretary of Labor may award to the prevailing employer a reasonable attorney's fee not exceeding $1,000.

"(4) REVIEW.—

"(A) APPEAL TO COURT OF APPEALS.—Any person adversely affected or aggrieved by an order issued under paragraph (3) may obtain review of the order in the United States Court of Appeals for the circuit in which the violation, with respect to which the order was issued, allegedly occurred or the circuit in which the complainant resided on the date of such violation. The petition for review must be filed not later than 60 days after the date of issuance of the final order of the Secretary of Labor. Review shall conform to chapter 7 of title 5, United States Code. The commencement of proceedings under this subparagraph shall not, unless ordered by the court, operate as a stay of the order.

"(B) LIMITATION ON COLLATERAL ATTACK.—An order of the Secretary of Labor with respect to which review could have been obtained under subparagraph (A) shall not be subject to judicial review in any criminal or other civil proceeding.

"(5) ENFORCEMENT OF ORDER BY SECRETARY OF LABOR.—Whenever any person has failed to comply with an order issued under paragraph (3), the Secretary of Labor may file a civil action in the United States district court for the district in which the violation was found to occur to enforce such order. In actions brought under this paragraph, the district courts shall have jurisdiction to grant all appropriate relief, including, but not to be limited to, injunctive relief and compensatory damages.

"(6) ENFORCEMENT OF ORDER BY PARTIES.—

"(A) COMMENCEMENT OF ACTION.—A person on whose behalf an order was issued under paragraph (3) may commence a civil action against the person or persons to whom such order was issued to require compliance with such order. The appropriate United States district court shall have jurisdiction, without regard to the amount in controversy or the citizenship of the parties, to enforce such order.

"(B) ATTORNEY FEES.—The court, in issuing any final order under this paragraph, may award costs of litigation (including reasonable attorney and expert witness fees) to any party whenever the court determines such award of costs is appropriate.

"(c) MANDAMUS.—Any nondiscretionary duty imposed by this section shall be enforceable in a mandamus proceeding brought under section 1361 of title 28, United States Code.

"(d) NONAPPLICABILITY TO DELIBERATE VIOLATIONS.—Subsection (a) shall not apply with respect to an action of an employee of an employer who, acting without direction from the employer (or such employer's agent), deliberately causes a violation of any requirement relating to pipeline safety under this chapter or any other law of the United States.".

(b) CIVIL PENALTY.—Section 60122(a) is amended by adding at the end the following:

"(3) A person violating section 60129, or an order issued thereunder, is liable to the Government for a civil penalty of not more than $1,000 for each violation. The penalties provided by paragraph (1) do not apply to a violation of section 60129 or an order issued thereunder.".

(c) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by adding at the end the following:

"60129. Protection of employees providing pipeline safety information ".

SEC. 7. SAFETY ORDERS.

Section 60117 is amended by adding at the end the following:

"(l) SAFETY ORDERS.—If the Secretary decides that a pipeline facility has a potential safety-related condition, the Secretary may order the operator of the facility to take necessary corrective action, including physical inspection, testing, repair, replacement, or other appropriate action to remedy the safety-related condition.".

SEC. 8. PENALTIES.

(a) PIPELINE FACILITIES HAZARDOUS TO LIFE, PROPERTY, OR THE ENVIRONMENT.—

(1) GENERAL AUTHORITY.—Section 60112(a) is amended to read as follows:

"(a) GENERAL AUTHORITY.—After notice and an opportunity for a hearing, the Secretary of Transportation may decide that a pipeline facility is hazardous if the Secretary decides that—

"(1) operation of the facility is or would be hazardous to life, property, or the environment; or

"(2) the facility is or would be constructed or operated, or a component of the facility is or would be constructed or operated, with equipment, material, or a technique that the Secretary decides is hazardous to life, property, or the environment.".

(2) CORRECTIVE ACTION ORDERS.—Section 60112(d) is amended by striking "is hazardous" and inserting "is or would be hazardous".

(b) ENFORCEMENT.—

(1) GENERAL PENALTIES.—Section 60122(a)(1) is amended—

(A) by striking "$25,000" and inserting "$100,000"; and

(B) by striking "$500,000" and inserting "$1,000,000".

(2) PENALTY CONSIDERATIONS.—Section 60122(b) is amended by striking "under this section" and all that follows through paragraph (4) and inserting "under this section—

"(1) the Secretary shall consider—

"(A) the nature, circumstances, and gravity of the violation, including adverse impact on the environment;

"(B) with respect to the violator, the degree of culpability, any history of prior violations, the ability to pay, and any effect on ability to continue doing business; and

"(C) good faith in attempting to comply; and

"(2) the Secretary may consider—

"(A) the economic benefit gained from the violation without any reduction because of subsequent damages; and

"(B) other matters that justice requires.".

(3) CIVIL ACTIONS.—Section 60120(a) is amended—

(A) by striking "(a) CIVIL ACTIONS.—(1)" and all that follows through "(2) At the request" and inserting the following:

"(a) CIVIL ACTIONS.—

"(1) CIVIL ACTIONS TO ENFORCE THIS CHAPTER.—At the request of the Secretary of Transportation, the Attorney General may bring a civil action in an appropriate district court of the United States to enforce this chapter, including section 60112, or a regulation prescribed or order issued under this chapter. The court may award appropriate relief, including a temporary or permanent injunction, punitive damages, and assessment of civil penalties, considering the same factors as prescribed for the Secretary in an administrative case under section 60122.

"(2) CIVIL ACTIONS TO REQUIRE COMPLIANCE WITH SUBPOENAS OR ALLOW FOR INSPECTIONS.—At the request"; and

(B) by aligning the remainder of the text of paragraph (2) with the text of paragraph (1).

(c) CRIMINAL PENALTIES FOR DAMAGING OR DESTROYING A FACILITY.—Section 60123(b) is amended—

(1) by striking "or" after "gas pipeline facility" and inserting ", an"; and

(2) by inserting after "liquid pipeline facility" the following: ", or either an intrastate gas pipeline facility or intrastate hazardous liquid pipeline facility that is used in interstate or foreign commerce or in any activity affecting interstate or foreign commerce".

49 USC 60122 note.

(d) COMPTROLLER GENERAL STUDY.—

(1) IN GENERAL.—The Comptroller General shall conduct a study of the actions, policies, and procedures of the Secretary of Transportation for assessing and collecting fines and penalties on operators of hazardous liquid and gas transmission pipelines.

(2) ANALYSIS.—In conducting the study, the Comptroller General shall examine, at a minimum, the following:

(A) The frequency with which the Secretary has substituted corrective orders for fines and penalties.

(B) Changes in the amounts of fines recommended by safety inspectors, assessed by the Secretary, and actually collected.

(C) An evaluation of the overall effectiveness of the Secretary's enforcement strategy.

(D) The extent to which the Secretary has complied with the report of the Government Accounting Office entitled "Pipeline Safety: The Office of Pipeline Safety is Changing How it Oversees the Pipeline Industry".

Deadline

(3) REPORT.—Not later than 1 year after the date of enactment of this Act, the Comptroller General shall transmit to the Committee on Commerce, Science, and Transportation of the Senate and the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives a report on the results of the study.

SEC. 9. PIPELINE SAFETY INFORMATION GRANTS TO COMMUNITIES.

(a) IN GENERAL.—Chapter 601 is further amended by adding at the end the following:

"§ 60130. Pipeline safety information grants to communities

"(a) GRANT AUTHORITY.—

"(1) IN GENERAL.—The Secretary of Transportation may make grants for technical assistance to local communities and groups of individuals (not including for-profit entities) relating to the safety of pipeline facilities in local communities, other than facilities regulated under Public Law 93–153 (43 U.S.C. 1651 et seq.). The Secretary shall establish competitive procedures for awarding grants under this section and criteria for selecting grant recipients. The amount of any grant under this section may not exceed $50,000 for a single grant recipient. The Secretary shall establish appropriate procedures to ensure the proper use of funds provided under this section. Procedures

"(2) TECHNICAL ASSISTANCE DEFINED.—In this subsection, the term 'technical assistance' means engineering and other scientific analysis of pipeline safety issues, including the promotion of public participation in official proceedings conducted under this chapter.

"(b) PROHIBITED USES.—Funds provided under this section may not be used for lobbying or in direct support of litigation.

"(c) ANNUAL REPORT.—

"(1) IN GENERAL.—Not later than 90 days after the last day of each fiscal year for which grants are made by the Secretary under this section, the Secretary shall report to the Committees on Commerce, Science, and Transportation and Energy and Natural Resources of the Senate and the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives on grants made under this section in the preceding fiscal year. Deadline

"(2) CONTENTS.—The report shall include—

"(A) a listing of the identity and location of each recipient of a grant under this section in the preceding fiscal year and the amount received by the recipient;

"(B) a description of the purpose for which each grant was made; and

"(C) a description of how each grant was used by the recipient.

"(d) AUTHORIZATION OF APPROPRIATIONS.—There is authorized to be appropriated to the Secretary of Transportation for carrying out this section $1,000,000 for each of the fiscal years 2003 through 2006. Such amounts shall not be derived from user fees collected under section 60301.".

(c) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by adding at the end the following:

"60130. Pipeline safety information grants to communities ".

SEC. 10. OPERATOR ASSISTANCE IN INVESTIGATIONS.

(a) IN GENERAL.—Section 60118 is amended by adding at the end the following:

"(e) OPERATOR ASSISTANCE IN INVESTIGATIONS.—If the Secretary or the National Transportation Safety Board investigate an accident involving a pipeline facility, the operator of the facility shall make available to the Secretary or the Board all records and information that in any way pertain to the accident (including integrity management plans and test results), and shall afford all reasonable assistance in the investigation of the accident.".

(b) CORRECTIVE ACTION ORDERS.—Section 60112(d) is amended—

(1) by striking "If the Secretary" and inserting the following:

"(1) IN GENERAL.—If the Secretary";

(2) by adding the end the following:

"(2) ACTIONS ATTRIBUTABLE TO AN EMPLOYEE.—If, in the case of a corrective action order issued following an accident, the Secretary determines that the actions of an employee carrying out an activity regulated under this chapter, including duties under section 60102(a), may have contributed substantially to the cause of the accident, the Secretary shall direct the operator to relieve the employee from performing those activities, reassign the employee, or place the employee on leave until the earlier of the date on which—

"(A) the Secretary, after notice and an opportunity for a hearing, determines that the employee's actions did not contribute substantially to the cause of the accident; or

"(B) the Secretary determines the employee has been re-qualified or re-trained as provided for in section 60131 and can safely perform those activities.

"(3) EFFECT OF COLLECTIVE BARGAINING AGREEMENTS.—An action taken by an operator under paragraph (2) shall be in accordance with the terms and conditions of any applicable collective bargaining agreement."; and

(3) by aligning the remainder of the text of paragraph (1) (as designated by paragraph (1) of this subsection) with paragraph (2) (as added by paragraph (2) of this subsection).

(c) LIMITATION ON STATUTORY CONSTRUCTION.—Section 60118 is amended by adding at the end the following:

"(f) LIMITATION ON STATUTORY CONSTRUCTION.—Nothing in this section may be construed to infringe upon the constitutional rights of an operator or its employees.".

SEC. 11. POPULATION ENCROACHMENT AND RIGHTS-OF-WAY.

(a) IN GENERAL.—Section 60127 is amended to read as follows:

"§ 60127. Population encroachment and rights-of-way

"(a) STUDY.—The Secretary of Transportation, in conjunction with the Federal Energy Regulatory Commission and in consultation with appropriate Federal agencies and State and local governments, shall undertake a study of land use practices, zoning ordinances, and preservation of environmental resources with regard to pipeline rights-of-way and their maintenance.

"(b) PURPOSE OF STUDY.—The purpose of the study shall be to gather information on land use practices, zoning ordinances, and preservation of environmental resources—

"(1) to determine effective practices to limit encroachment on existing pipeline rights-of-way;

"(2) to address and prevent the hazards and risks to the public, pipeline workers, and the environment associated with encroachment on pipeline rights-of-way;

"(3) to raise the awareness of the risks and hazards of encroachment on pipeline rights-of-way; and

"(4) to address how to best preserve environmental resources in conjunction with maintaining pipeline rights-of-way, recognizing pipeline operators' regulatory obligations to maintain rights-of-way and to protect public safety.

"(c) CONSIDERATIONS.—In conducting the study, the Secretary shall consider, at a minimum, the following:

"(1) The legal authority of Federal agencies and State and local governments in controlling land use and the limitations on such authority.

"(2) The current practices of Federal agencies and State and local governments in addressing land use issues involving a pipeline easement.

"(3) The most effective way to encourage Federal agencies and State and local governments to monitor and reduce encroachment upon pipeline rights-of-way.

"(d) REPORT.—

"(1) IN GENERAL.—Not later than 1 year after the date of enactment of this subsection, the Secretary shall publish a report identifying practices, laws, and ordinances that are most successful in addressing issues of encroachment and maintenance on pipeline rights-of-way so as to more effectively protect public safety, pipeline workers, and the environment.

Deadline Publication.

"(2) DISTRIBUTION OF REPORT.—The Secretary shall provide a copy of the report to—

"(A) Congress and appropriate Federal agencies; and

"(B) States for further distribution to appropriate local authorities.

"(3) ADOPTION OF PRACTICES, LAWS, AND ORDINANCES.—The Secretary shall encourage Federal agencies and State and local governments to adopt and implement appropriate practices, laws, and ordinances, as identified in the report, to address the risks and hazards associated with encroachment upon pipeline rights-of-way and to address the potential methods of preserving environmental resources while maintaining pipeline rights-of-way, consistent with pipeline safety.".

(b) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by striking the item relating to section 60127 and inserting the following:

"60127 Population encroachment and rights-of-way.".

SEC. 12. PIPELINE INTEGRITY, SAFETY, AND RELIABILITY RESEARCH AND DEVELOPMENT.

49 USC 60101 note

(a) IN GENERAL.—The heads of the participating agencies shall carry out a program of research, development, demonstration, and standardization to ensure the integrity of pipeline facilities.

(b) MEMORANDUM OF UNDERSTANDING.—

(1) IN GENERAL.—Not later than 120 days after the date of enactment of this Act, the heads of the participating agencies shall enter into a memorandum of understanding detailing their respective responsibilities in the program authorized by subsection (a).

Deadline

(2) AREAS OF EXPERTISE.—Under the memorandum of understanding, each of the participating agencies shall have the primary responsibility for ensuring that the elements of the program within its expertise are implemented in accordance with this section. The Department of Transportation's responsibilities shall reflect its lead role in pipeline safety and expertise in pipeline inspection, integrity management, and damage prevention. The Department of Energy's responsibilities shall reflect its expertise in system reliability, low-volume gas leak detection, and surveillance technologies. The National Institute of Standards and Technology's responsibilities shall reflect its

expertise in materials research and assisting in the development of consensus technical standards, as that term is used in section 12(d)(4) of Public Law 104–13 (15 U.S.C. 272 note).

(c) PROGRAM ELEMENTS.—The program authorized by subsection (a) shall include research, development, demonstration, and standardization activities related to—

(1) materials inspection;

(2) stress and fracture analysis, detection of cracks, corrosion, abrasion, and other abnormalities inside pipelines that lead to pipeline failure, and development of new equipment or technologies that are inserted into pipelines to detect anomalies;

(3) internal inspection and leak detection technologies, including detection of leaks at very low volumes;

(4) methods of analyzing content of pipeline throughput;

(5) pipeline security, including improving the real-time surveillance of pipeline rights-of-way, developing tools for evaluating and enhancing pipeline security and infrastructure, reducing natural, technological, and terrorist threats, and protecting first response units and persons near an incident;

(6) risk assessment methodology, including vulnerability assessment and reduction of third-party damage;

(7) communication, control, and information systems surety;

(8) fire safety of pipelines;

(9) improved excavation, construction, and repair technologies; and

(10) other appropriate elements.

(d) PROGRAM PLAN.—

Deadline

(1) IN GENERAL.—Not later than 1 year after the date of enactment of this section, the Secretary of Transportation, in coordination with the Secretary of Energy and the Director of the National Institute of Standards and Technology, shall prepare and transmit to Congress a 5-year program plan to guide activities under this section. Such program plan shall be submitted to the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee for review, and the report to Congress shall include the comments of the committees. The 5-year program plan shall be based on the memorandum of understanding under subsection (b) and take into account related activities of other Federal agencies.

(2) CONSULTATION.—In preparing the program plan and selecting and prioritizing appropriate project proposals, the Secretary of Transportation shall consult with or seek the advice of appropriate representatives of the natural gas, crude oil, and petroleum product pipeline industries, utilities, manufacturers, institutions of higher learning, Federal agencies, pipeline research institutions, national laboratories, State pipeline safety officials, labor organizations, environmental organizations, pipeline safety advocates, and professional and technical societies.

Deadline.

(e) REPORTS TO CONGRESS.—Not later than 1 year after the date of enactment of this Act, and annually thereafter, the heads of the participating agencies shall transmit jointly to Congress a report on the status and results to date of the implementation of the program plan prepared under subsection (d).

(f) AUTHORIZATION OF APPROPRIATIONS.—

(1) DEPARTMENT OF TRANSPORTATION.—There is authorized to be appropriated to the Secretary of Transportation for carrying out this section $10,000,000 for each of the fiscal years 2003 through 2006.

(2) DEPARTMENT OF ENERGY.—There is authorized to be appropriated to the Secretary of Energy for carrying out this section $10,000,000 for each of the fiscal years 2003 through 2006.

(3) NATIONAL INSTITUTE OF STANDARDS AND TECHNOLOGY.—There is authorized to be appropriated to the Director of the National Institute of Standards and Technology for carrying out this section $5,000,000 for each of the fiscal years 2003 through 2006.

(4) GENERAL REVENUE FUNDING.—Any sums appropriated under this subsection shall be derived from general revenues and may not be derived from amounts collected under section 60301 of title 49, United States Code.

(g) PIPELINE INTEGRITY PROGRAM.—Of the amounts available in the Oil Spill Liability Trust Fund established by section 9509 of the Internal Revenue Code of 1986 (26 U.S.C. 9509), $3,000,000 shall be transferred to the Secretary of Transportation, as provided in appropriation Acts, to carry out programs for detection, prevention, and mitigation of oil spills for each of the fiscal years 2003 through 2006.

(h) PARTICIPATING AGENCIES DEFINED.—In this section, the term "participating agencies" means the Department of Transportation, the Department of Energy, and the National Institute of Standards and Technology.

SEC. 13. PIPELINE QUALIFICATION PROGRAMS.

(a) VERIFICATION PROGRAM.—

(1) IN GENERAL.—Chapter 601 is further amended by adding at the end the following:

"§ 60131. Verification of pipeline qualification programs

"(a) IN GENERAL.—Subject to the requirements of this section, the Secretary of Transportation shall require the operator of a pipeline facility to develop and adopt a qualification program to ensure that the individuals who perform covered tasks are qualified to conduct such tasks.

"(b) STANDARDS AND CRITERIA.—

"(1) DEVELOPMENT.—Not later than 1 year after the date of enactment of this section, the Secretary shall ensure that the Department of Transportation has in place standards and criteria for qualification programs referred to in subsection (a). Deadline

"(2) CONTENTS.—The standards and criteria shall include the following:

"(A) The establishment of methods for evaluating the acceptability of the qualifications of individuals described in subsection (a).

"(B) A requirement that pipeline operators develop and implement written plans and procedures to qualify individuals described in subsection (a) to a level found acceptable using the methods established under subparagraph (A) and evaluate the abilities of individuals described in subsection (a) according to such methods.

"(C) A requirement that the plans and procedures adopted by a pipeline operator under subparagraph (B) be reviewed and verified under subsection (e).

Deadline

"(c) DEVELOPMENT OF QUALIFICATION PROGRAMS BY PIPELINE OPERATORS.—The Secretary shall require each pipeline operator to develop and adopt, not later than 2 years after the date of enactment of this section, a qualification program that complies with the standards and criteria described in subsection (b).

"(d) ELEMENTS OF QUALIFICATION PROGRAMS.—A qualification program adopted by an operator under subsection (a) shall include, at a minimum, the following elements:

"(1) A method for examining or testing the qualifications of individuals described in subsection (a). The method may include written examination, oral examination, observation during on-the-job performance, on-the-job training, simulations, and other forms of assessment. The method may not be limited to observation of on-the-job performance, except with respect to tasks for which the Secretary has determined that such observation is the best method of examining or testing qualifications. The Secretary shall ensure that the results of any such observations are documented in writing.

Records

Deadline

"(2) A requirement that the operator complete the qualification of all individuals described in subsection (a) not later than 18 months after the date of adoption of the qualification program.

"(3) A periodic requalification component that provides for examination or testing of individuals in accordance with paragraph (1).

"(4) A program to provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities.

"(e) REVIEW AND VERIFICATION OF PROGRAMS.—

"(1) IN GENERAL.—The Secretary shall review the qualification program of each pipeline operator and verify its compliance with the standards and criteria described in subsection (b) and that it includes the elements described in subsection (d). The Secretary shall record the results of that review for use in the next review of an operator's program.

Records.

"(2) DEADLINE FOR COMPLETION.—Reviews and verifications under this subsection shall be completed not later than 3 years after the date of the enactment of this section.

"(3) INADEQUATE PROGRAMS.—If the Secretary decides that a qualification program is inadequate for the safe operation of a pipeline facility, the Secretary shall act as under section 60108(a)(2) to require the operator to revise the qualification program.

Notification.

"(4) PROGRAM MODIFICATIONS.—If the operator of a pipeline facility significantly modifies a program that has been verified under this subsection, the operator shall notify the Secretary of the modifications. The Secretary shall review and verify such modifications in accordance with paragraph (1).

"(5) WAIVERS AND MODIFICATIONS.—In accordance with section 60118(c), the Secretary may waive or modify any requirement of this section if the waiver or modification is not inconsistent with pipeline safety.

"(6) INACTION BY THE SECRETARY.—Notwithstanding any failure of the Secretary to prescribe standards and criteria as described in subsection (b), an operator of a pipeline facility shall develop and adopt a qualification program that complies with the requirement of subsection (b)(2)(B) and includes the elements described in subsection (d) not later than 2 years after the date of enactment of this section. Deadline

"(f) INTRASTATE PIPELINE FACILITIES.—In the case of an intrastate pipeline facility operator, the duties and powers of the Secretary under this section with respect to the qualification program of the operator shall be vested in the appropriate State regulatory agency, consistent with this chapter.

"(g) COVERED TASK DEFINED.—In this section, the term 'covered task'—

"(1) with respect to a gas pipeline facility, has the meaning such term has under section 192.801 of title 49, Code of Federal Regulations, including any subsequent modifications; and

"(2) with respect to a hazardous liquid pipeline facility, has the meaning such term has under section 195.501 of such title, including any subsequent modifications.

"(h) REPORT.—Not later than 4 years after the date of enactment of this section, the Secretary shall transmit to Congress a report on the status and results to date of the personnel qualification regulations issued under this chapter.". Deadline

(2) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by adding at end the following:

"60131 Verification of pipeline qualification programs."

(b) PILOT PROGRAM FOR CERTIFICATION OF CERTAIN PIPELINE WORKERS.— 49 USC 60131 note

(1) IN GENERAL.—Not later than 36 months after the date of enactment of this Act, the Secretary of Transportation shall— Deadline.

(A) develop tests and other requirements for certifying the qualifications of individuals who operate computer-based systems for controlling the operations of pipelines; and

(B) establish and carry out a pilot program for 3 pipeline facilities under which the individuals operating computer-based systems for controlling the operations of pipelines at such facilities are required to be certified under the process established under subparagraph (A).

(2) REPORT.—The Secretary shall include in the report required under section 60131(h), as added by subsection (a) of this section, the results of the pilot program. The report shall include—

(A) a description of the pilot program and implementation of the pilot program at each of the 3 pipeline facilities;

(B) an evaluation of the pilot program, including the effectiveness of the process for certifying individuals who operate computer-based systems for controlling the operations of pipelines;

(C) any recommendations of the Secretary for requiring the certification of all individuals who operate computer-based systems for controlling the operations of pipelines; and

(D) an assessment of the ramifications of requiring the certification of other individuals performing safety-sensitive functions for a pipeline facility.

(3) COMPUTER-BASED SYSTEMS DEFINED.—In this subsection, the term "computer-based systems" means supervisory control and data acquisition systems.

SEC. 14. RISK ANALYSIS AND INTEGRITY MANAGEMENT PROGRAMS FOR GAS PIPELINES.

(a) IN GENERAL.—Section 60109 is amended by adding at the end the following:

"(c) RISK ANALYSIS AND INTEGRITY MANAGEMENT PROGRAMS.—

"(1) REQUIREMENT.—Each operator of a gas pipeline facility shall conduct an analysis of the risks to each facility of the operator located in an area identified pursuant to subsection (a)(1) and defined in chapter 192 of title 49, Code of Federal Regulations, including any subsequent modifications, and shall adopt and implement a written integrity management program for such facility to reduce the risks.

"(2) REGULATIONS.—

Deadlines

"(A) IN GENERAL.—Not later than 12 months after the date of enactment of this subsection, the Secretary shall issue regulations prescribing standards to direct an operator's conduct of a risk analysis and adoption and implementation of an integrity management program under this subsection. The regulations shall require an operator to conduct a risk analysis and adopt an integrity management program within a time period prescribed by the Secretary, ending not later than 24 months after such date of enactment. Not later than 18 months after such date of enactment, each operator of a gas pipeline facility shall begin a baseline integrity assessment described in paragraph (3).

"(B) AUTHORITY TO ISSUE REGULATIONS.—The Secretary may satisfy the requirements of this paragraph through the issuance of regulations under this paragraph or under other authority of law.

"(3) MINIMUM REQUIREMENTS OF INTEGRITY MANAGEMENT PROGRAMS.—An integrity management program required under paragraph (1) shall include, at a minimum, the following requirements:

Deadlines

"(A) A baseline integrity assessment of each of the operator's facilities in areas identified pursuant to subsection (a)(1) and defined in chapter 192 of title 49, Code of Federal Regulations, including any subsequent modifications, by internal inspection device, pressure testing, direct assessment, or an alternative method that the Secretary determines would provide an equal or greater level of safety. The operator shall complete such assessment not later than 10 years after the date of enactment of this subsection. At least 50 percent of such facilities shall be assessed not later than 5 years after such date of enactment. The operator shall prioritize such facilities for assessment based on all risk factors, including any previously discovered defects or anomalies and any history of leaks, repairs, or failures. The operator shall ensure that assessments of facilities with the highest risks are given priority for completion and that such assessments will be completed not later than 5 years after such date of enactment.

"(B) Subject to paragraph (5), periodic reassessment of the facility, at a minimum of once every 7 years, using methods described in subparagraph (A).

"(C) Clearly defined criteria for evaluating the results of assessments conducted under subparagraphs (A) and (B) and for taking actions based on such results.

"(D) A method for conducting an analysis on a continuing basis that integrates all available information about the integrity of the facility and the consequences of releases from the facility.

"(E) A description of actions to be taken by the operator to promptly address any integrity issue raised by an evaluation conducted under subparagraph (C) or the analysis conducted under subparagraph (D).

"(F) A description of measures to prevent and mitigate the consequences of releases from the facility.

"(G) A method for monitoring cathodic protection systems throughout the pipeline system of the operator to the extent not addressed by other regulations.

"(H) If the Secretary raises a safety concern relating to the facility, a description of the actions to be taken by the operator to address the safety concern, including issues raised with the Secretary by States and local authorities under an agreement entered into under section 60106.

"(4) TREATMENT OF BASELINE INTEGRITY ASSESSMENTS.—In the case of a baseline integrity assessment conducted by an operator in the period beginning on the date of enactment of this subsection and ending on the date of issuance of regulations under this subsection, the Secretary shall accept the assessment as complete, and shall not require the operator to repeat any portion of the assessment, if the Secretary determines that the assessment was conducted in accordance with the requirements of this subsection.

"(5) WAIVERS AND MODIFICATIONS.—In accordance with section 60118(c), the Secretary may waive or modify any requirement for reassessment of a facility under paragraph (3)(B) for reasons that may include the need to maintain local product supply or the lack of internal inspection devices if the Secretary determines that such waiver is not inconsistent with pipeline safety.

"(6) STANDARDS.—The standards prescribed by the Secretary under paragraph (2) shall address each of the following factors:

"(A) The minimum requirements described in paragraph (3).

"(B) The type or frequency of inspections or testing of pipeline facilities, in addition to the minimum requirements of paragraph (3)(B).

"(C) The manner in which the inspections or testing are conducted.

"(D) The criteria used in analyzing results of the inspections or testing.

"(E) The types of information sources that must be integrated in assessing the integrity of a pipeline facility as well as the manner of integration.

"(F) The nature and timing of actions selected to address the integrity of a pipeline facility.

"(G) Such other factors as the Secretary determines appropriate to ensure that the integrity of a pipeline facility is addressed and that appropriate mitigative measures are adopted to protect areas identified under subsection (a)(1).

In prescribing those standards, the Secretary shall ensure that all inspections required are conducted in a manner that minimizes environmental and safety risks, and shall take into account the applicable level of protection established by national consensus standards organizations.

"(7) ADDITIONAL OPTIONAL STANDARDS.—The Secretary may also prescribe standards requiring an operator of a pipeline facility to include in an integrity management program under this subsection—

"(A) changes to valves or the establishment or modification of systems that monitor pressure and detect leaks based on the operator's risk analysis; and

"(B) the use of emergency flow restricting devices.

Deadlines

"(8) LACK OF REGULATIONS.—In the absence of regulations addressing the elements of an integrity management program described in this subsection, the operator of a pipeline facility shall conduct a risk analysis and adopt and implement an integrity management program described in this subsection not later than 24 months after the date of enactment of this subsection and shall complete the baseline integrity assessment described in this subsection not later than 10 years after such date of enactment. At least 50 percent of such facilities shall be assessed not later than 5 years after such date of enactment. The operator shall prioritize such facilities for assessment based on all risk factors, including any previously discovered defects or anomalies and any history of leaks, repairs, or failures. The operator shall ensure that assessments of facilities with the highest risks are given priority for completion and that such assessments will be completed not later than 5 years after such date of enactment.

"(9) REVIEW OF INTEGRITY MANAGEMENT PROGRAMS.—

"(A) REVIEW OF PROGRAMS.—

"(i) IN GENERAL.—The Secretary shall review a risk analysis and integrity management program under paragraph (1) and record the results of that review for use in the next review of an operator's program.

"(ii) CONTEXT OF REVIEW.—The Secretary may conduct a review under clause (i) as an element of the Secretary's inspection of an operator.

"(iii) INADEQUATE PROGRAMS.—If the Secretary determines that a risk analysis or integrity management program does not comply with the requirements of this subsection or regulations issued as described in paragraph (2), or is inadequate for the safe operation of a pipeline facility, the Secretary shall act under section 60108(a)(2) to require the operator to revise the risk analysis or integrity management program.

"(B) AMENDMENTS TO PROGRAMS.—In order to facilitate reviews under this paragraph, an operator of a pipeline facility shall notify the Secretary of any amendment made to the operator's integrity management program not later than 30 days after the date of adoption of the amendment. The Secretary shall review any such amendment in accordance with this paragraph. Notification. Deadline.

"(C) TRANSMITTAL OF PROGRAMS TO STATE AUTHORITIES.—The Secretary shall provide a copy of each risk analysis and integrity management program reviewed by the Secretary under this paragraph to any appropriate State authority with which the Secretary has entered into an agreement under section 60106.

"(10) STATE REVIEW OF INTEGRITY MANAGEMENT PLANS.—A State authority that enters into an agreement pursuant to section 60106, permitting the State authority to review the risk analysis and integrity management program pursuant to paragraph (9), may provide the Secretary with a written assessment of the risk analysis and integrity management program, make recommendations, as appropriate, to address safety concerns not adequately addressed by the operator's risk analysis or integrity management program, and submit documentation explaining the State-proposed revisions. The Secretary shall consider carefully the State's proposals and work in consultation with the States and operators to address safety concerns.

"(11) APPLICATION OF STANDARDS.—Section 60104(b) shall not apply to this section.".

(b) INTEGRITY MANAGEMENT REGULATIONS.—Section 60109 is further amended by adding at the end the following:

"(d) EVALUATION OF INTEGRITY MANAGEMENT REGULATIONS.—Not later than 4 years after the date of enactment of this subsection, the Comptroller General shall complete an assessment and evaluation of the effects on public safety and the environment of the requirements for the implementation of integrity management programs contained in the standards prescribed as described in subsection (c)(2).". Deadline.

(c) CONFORMING AMENDMENT.—Section 60118(a) is amended—

(1) by striking "and" at the end of paragraph (2);

(2) by striking the period at the end of paragraph (3) and inserting "; and"; and

(3) by adding at the end the following.

"(4) conduct a risk analysis, and adopt and implement an integrity management program, for pipeline facilities as required under section 60109(c).".

(d) STUDY OF REASSESSMENT INTERVALS.—

(1) STUDY.—The Comptroller General shall conduct a study to evaluate the 7-year reassessment interval required by section 60109(c)(3)(B) of title 49, United States Code, as added by subsection (a) of this section. 49 USC 60109 note.

(2) REPORT.—Not later than 4 years after the date of the enactment of this Act, the Comptroller General shall transmit to Congress a report on the results of the study conducted under paragraph (1). Deadline

SEC. 15. NATIONAL PIPELINE MAPPING SYSTEM.

(a) IN GENERAL.—Chapter 601 is further amended by adding at the end the following:

"§ 60132. National pipeline mapping system

Deadline

"(a) INFORMATION TO BE PROVIDED.—Not later than 6 months after the date of enactment of this section, the operator of a pipeline facility (except distribution lines and gathering lines) shall provide to the Secretary of Transportation the following information with respect to the facility:

"(1) Geospatial data appropriate for use in the National Pipeline Mapping System or data in a format that can be readily converted to geospatial data.

"(2) The name and address of the person with primary operational control to be identified as its operator for purposes of this chapter.

"(3) A means for a member of the public to contact the operator for additional information about the pipeline facilities it operates.

"(b) UPDATES.—A person providing information under subsection (a) shall provide to the Secretary updates of the information to reflect changes in the pipeline facility owned or operated by the person and as otherwise required by the Secretary.

"(c) TECHNICAL ASSISTANCE TO IMPROVE LOCAL RESPONSE CAPABILITIES.—The Secretary may provide technical assistance to State and local officials to improve local response capabilities for pipeline emergencies by adapting information available through the National Pipeline Mapping System to software used by emergency response personnel responding to pipeline emergencies.".

(b) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by adding at the end the following:

"60132 National pipeline mapping system ".

SEC. 16. COORDINATION OF ENVIRONMENTAL REVIEWS.

(a) IN GENERAL.—Chapter 601 is further amended by adding at the end the following:

"§ 60133. Coordination of environmental reviews

"(a) INTERAGENCY COMMITTEE.—

Deadline
President

"(1) ESTABLISHMENT AND PURPOSE.—Not later than 30 days after the date of enactment of this section, the President shall establish an Interagency Committee to develop and ensure implementation of a coordinated environmental review and permitting process in order to enable pipeline operators to commence and complete all activities necessary to carry out pipeline repairs within any time periods specified by rule by the Secretary

"(2) MEMBERSHIP.—The Chairman of the Council on Environmental Quality (or a designee of the Chairman) shall chair the Interagency Committee, which shall consist of representatives of Federal agencies with responsibilities relating to pipeline repair projects, including each of the following persons (or a designee thereof):

"(A) The Secretary of Transportation.

"(B) The Administrator of the Environmental Protection Agency.

"(C) The Director of the United States Fish and Wildlife Service.

"(D) The Assistant Administrator for Fisheries of the National Oceanic and Atmospheric Administration.

"(E) The Director of the Bureau of Land Management.
"(F) The Director of the Minerals Management Service.
"(G) The Assistant Secretary of the Army for Civil Works.
"(H) The Chairman of the Federal Energy Regulatory Commission.

"(3) EVALUATION.—The Interagency Committee shall evaluate Federal permitting requirements to which access, excavation, and restoration activities in connection with pipeline repairs described in paragraph (1) may be subject. As part of its evaluation, the Interagency Committee shall examine the access, excavation, and restoration practices of the pipeline industry in connection with such pipeline repairs, and may develop a compendium of best practices used by the industry to access, excavate, and restore the site of a pipeline repair.

"(4) MEMORANDUM OF UNDERSTANDING.—Based upon the evaluation required under paragraph (3) and not later than 1 year after the date of enactment of this section, the members of the Interagency Committee shall enter into a memorandum of understanding to provide for a coordinated and expedited pipeline repair permit review process to carry out the purpose set forth in paragraph (1). The Interagency Committee shall include provisions in the memorandum of understanding identifying those repairs or categories of repairs described in paragraph (1) for which the best practices identified under paragraph (3), when properly employed by a pipeline operator, would result in no more than minimal adverse effects on the environment and for which discretionary administrative reviews may therefore be minimized or eliminated. With respect to pipeline repairs described in paragraph (1) to which the preceding sentence would not be applicable, the Interagency Committee shall include provisions to enable pipeline operators to commence and complete all activities necessary to carry out pipeline repairs within any time periods specified by rule by the Secretary. The Interagency Committee shall include in the memorandum of understanding criteria under which permits required for such pipeline repair activities should be prioritized over other less urgent agency permit application reviews. The Interagency Committee shall not enter into a memorandum of understanding under this paragraph except by unanimous agreement of the members of the Interagency Committee. Deadline

"(5) STATE AND LOCAL CONSULTATION.—In carrying out this subsection, the Interagency Committee shall consult with appropriate State and local environmental, pipeline safety, and emergency response officials, and such other officials as the Interagency Committee considers appropriate.

"(b) IMPLEMENTATION.—Not later than 180 days after the completion of the memorandum of understanding required under subsection (a)(4), each agency represented on the Interagency Committee shall revise its regulations as necessary to implement the provisions of the memorandum of understanding. Deadline.

"(c) SAVINGS PROVISIONS; NO PREEMPTION.—Nothing in this section shall be construed—

"(1) to require a pipeline operator to obtain a Federal permit, if no Federal permit would otherwise have been required under Federal law; or

"(2) to preempt applicable Federal, State, or local environmental law.

"(d) INTERIM OPERATIONAL ALTERNATIVES.—

Deadline. Regulations.

"(1) IN GENERAL.—Not later than 30 days after the date of enactment of this section, and subject to the limitations in paragraph (2), the Secretary of Transportation shall revise the regulations of the Department, to the extent necessary, to permit a pipeline operator subject to time periods for repair specified by rule by the Secretary to implement alternative mitigation measures until all applicable permits have been granted.

"(2) LIMITATIONS.—The regulations issued by the Secretary pursuant to this subsection shall not allow an operator to implement alternative mitigation measures pursuant to paragraph (1) unless—

"(A) allowing the operator to implement such measures would be consistent with the protection of human health, public safety, and the environment;

"(B) the operator, with respect to a particular repair project, has applied for and is pursuing diligently and in good faith all required Federal, State, and local permits to carry out the project; and

"(C) the proposed alternative mitigation measures are not incompatible with pipeline safety

"(e) OMBUDSMAN.—The Secretary shall designate an ombudsman to assist in expediting pipeline repairs and resolving disagreements between Federal, State, and local permitting agencies and the pipeline operator during agency review of any pipeline repair activity, consistent with protection of human health, public safety, and the environment.

"(f) STATE AND LOCAL PERMITTING PROCESSES.—The Secretary shall encourage States and local governments to consolidate their respective permitting processes for pipeline repair projects subject to any time periods for repair specified by rule by the Secretary. The Secretary may request other relevant Federal agencies to provide technical assistance to States and local governments for the purpose of encouraging such consolidation.".

(b) CONFORMING AMENDMENT.—The analysis for chapter 601 is amended by adding at the end the following:

"60133 Coordination of environmental reviews."

49 USC 60114 note.

SEC. 17. NATIONWIDE TOLL-FREE NUMBER SYSTEM.

Within 1 year after the date of the enactment of this Act, the Secretary of Transportation shall, in conjunction with the Federal Communications Commission, facility operators, excavators, and one-call notification system operators, provide for the establishment of a 3-digit nationwide toll-free telephone number system to be used by State one-call notification systems.

SEC. 18. IMPLEMENTATION OF INSPECTOR GENERAL RECOMMENDATIONS.

(a) IN GENERAL.—Except as otherwise required by this Act, the Secretary of Transportation shall implement the safety improvement recommendations provided for in the Department of Transportation Inspector General's Report (RT–2000–069).

Deadlines

(b) REPORTS BY THE SECRETARY.—Not later than 90 days after the date of enactment of this Act, and every 90 days thereafter until each of the recommendations referred to in subsection (a) has been implemented, the Secretary shall transmit to the Committee on Commerce, Science, and Transportation of the Senate and the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives a report on the specific actions taken to implement such recommendations.

(c) REPORTS BY THE INSPECTOR GENERAL.—The Inspector General shall periodically transmit to the committees referred to in subsection (b) a report assessing the Secretary's progress in implementing the recommendations referred to in subsection (a) and identifying options for the Secretary to consider in accelerating recommendation implementation.

SEC. 19. NTSB SAFETY RECOMMENDATIONS. 49 USC 1135 note

(a) IN GENERAL.—The Secretary of Transportation, the Administrator of Research and Special Program Administration, and the Director of the Office of Pipeline Safety shall fully comply with section 1135 of title 49, United States Code, to ensure timely responsiveness to National Transportation Safety Board recommendations about pipeline safety.

(b) PUBLIC AVAILABILITY.—The Secretary, Administrator, or Director, respectively, shall make a copy of each recommendation on pipeline safety and response, as described in subsections (a) and (b) of section 1135, title 49, United States Code.

(c) REPORTS TO CONGRESS.—The Secretary, Administrator, or Director, respectively, shall submit to Congress by January 1 of each year a report containing each recommendation on pipeline safety made by the Board during the prior year and a copy of the response to each such recommendation. Deadline

SEC. 20. MISCELLANEOUS AMENDMENTS.

(a) GENERAL AUTHORITY AND PURPOSE.—

(1) IN GENERAL.—Section 60102(a) is amended—

(A) by redesignating paragraph (2) as paragraph (3);

(B) by striking "(a)(1)" and all that follows through "The Secretary of Transportation" and inserting the following:

"(a) PURPOSE AND MINIMUM SAFETY STANDARDS.—

"(1) PURPOSE.—The purpose of this chapter is to provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities by improving the regulatory and enforcement authority of the Secretary of Transportation.

"(2) MINIMUM SAFETY STANDARDS.—The Secretary";

(C) by moving the remainder of the text of paragraph (2) (as so redesignated), including subparagraphs (A) and (B) but excluding subparagraph (C), 2 ems to the right; and

(D) in paragraph (3) (as so redesignated) by inserting "QUALIFICATIONS OF PIPELINE OPERATORS.—" before "The qualifications".

(2) CONFORMING AMENDMENTS.—Chapter 601 is amended—

(A) by striking the heading for section 60102 and inserting the following:

"§ 60102. Purpose and general authority"; and

(B) in the analysis for such chapter by striking the item relating to section 60102 and inserting the following:

"60102. Purpose and general authority.".

(b) CONFLICTS OF INTEREST.—Section 60115(b)(4) is amended by adding at the end the following:

"(D) None of the individuals selected for a committee under paragraph (3)(C) may have a significant financial interest in the pipeline, petroleum, or gas industry.".

SEC. 21. TECHNICAL AMENDMENTS.

Chapter 601 is amended—

(1) in section 60110(b) by striking "circumstances" and all that follows through "operator" and inserting the following: "circumstances, if any, under which an operator";

(2) in section 60114 by redesignating subsection (d) as subsection (c);

(3) in section 60122(a)(1) by striking "section 60114(c)" and inserting "section 60114(b)"; and

(4) in section 60123(a) by striking "60114(c)" and inserting "60114(b)".

SEC. 22. AUTHORIZATION OF APPROPRIATIONS.

(a) GAS AND HAZARDOUS LIQUID.—Section 60125(a) is amended to read as follows:

"(a) GAS AND HAZARDOUS LIQUID.—To carry out this chapter (except for section 60107) related to gas and hazardous liquid, the following amounts are authorized to be appropriated to the Department of Transportation:

"(1) $45,800,000 for fiscal year 2003, of which $31,900,000 is to be derived from user fees for fiscal year 2003 collected under section 60301 of this title.

"(2) $46,800,000 for fiscal year 2004, of which $35,700,000 is to be derived from user fees for fiscal year 2004 collected under section 60301 of this title.

"(3) $47,100,000 for fiscal year 2005, of which $41,100,000 is to be derived from user fees for fiscal year 2005 collected under section 60301 of this title.

"(4) $50,000,000 for fiscal year 2006, of which $45,000,000 is to be derived from user fees for fiscal year 2006 collected under section 60301 of this title.".

(b) STATE GRANTS.—Section 60125 is amended—

(1) by striking subsections (b), (d), and (f) and redesignating subsection (c) as subsection (b); and

(2) in subsection (b)(1) (as so redesignated) by striking subparagraphs (A) through (H) and inserting the following:

"(A) $19,800,000 for fiscal year 2003, of which $14,800,000 is to be derived from user fees for fiscal year 2003 collected under section 60301 of this title.

"(B) $21,700,000 for fiscal year 2004, of which $16,700,000 is to be derived from user fees for fiscal year 2004 collected under section 60301 of this title.

"(C) $24,600,000 for fiscal year 2005, of which $19,600,000 is to be derived from user fees for fiscal year 2005 collected under section 60301 of this title.

"(D) $26,500,000 for fiscal year 2006, of which $21,500,000 is to be derived from user fees for fiscal year 2006 collected under section 60301 of this title.".

(c) OIL SPILLS; EMERGENCY RESPONSE GRANTS.—Section 60125 is amended by inserting after subsection (b) (as redesignated by subsection (b)(1) of this section) the following:

"(c) OIL SPILL LIABILITY TRUST FUND.—Of the amounts available in the Oil Spill Liability Trust Fund, $8,000,000 shall be transferred to the Secretary of Transportation, as provided in appropriation Acts, to carry out programs authorized in this chapter for each of fiscal years 2003 through 2006.

"(d) EMERGENCY RESPONSE GRANTS.—

"(1) IN GENERAL.—The Secretary may establish a program for making grants to State, county, and local governments in high consequence areas, as defined by the Secretary, for emergency response management, training, and technical assistance.

"(2) AUTHORIZATION OF APPROPRIATIONS.—There is authorized to be appropriated $6,000,000 for each of fiscal years 2003 through 2006 to carry out this subsection.".

(d) CONFORMING AMENDMENT.—Section 60125(e) is amended by striking "or (b) of this section".

SEC. 23. INSPECTIONS BY DIRECT ASSESSMENT.

Section 60102, as amended by this Act, is further amended by adding at the end the following:

"(m) INSPECTIONS BY DIRECT ASSESSMENT.—Not later than 1 year after the date of the enactment of this subsection, the Secretary shall issue regulations prescribing standards for inspection of a pipeline facility by direct assessment.". Deadline Regulations.

SEC. 24. STATE PIPELINE SAFETY ADVISORY COMMITTEES. 49 USC 60102 note Deadline

Within 90 days after receiving recommendations for improvements to pipeline safety from an advisory committee appointed by the Governor of any State, the Secretary of Transportation shall respond in writing to the committee setting forth what action, if any, the Secretary will take on those recommendations and the Secretary's reasons for acting or not acting upon any of the recommendations.

SEC. 25. PIPELINE BRIDGE RISK STUDY. 49 USC 60108 note

(a) IN GENERAL.—The Secretary of Transportation shall conduct a study to determine whether cable-suspension pipeline bridges pose structural or other risks warranting particularized attention in connection with pipeline operators risk assessment programs and whether particularized inspection standards need to be developed by the Department of Transportation to recognize the peculiar risks posed by such bridges.

(b) PUBLIC PARTICIPATION AND COMMENTS.—In conducting the study, the Secretary shall provide, to the maximum extent practicable, for public participation and comment and shall solicit views and comments from the public and interested persons, including participants in the pipeline industry with knowledge and experience in inspection of pipeline facilities.

(c) COMPLETION AND REPORT.—Within 2 years after the date of enactment of this Act, the Secretary shall complete the study and transmit to Congress a report detailing the results of the study. Deadline.

(d) FUNDING.—The Secretary may carry out this section using only amounts that are specifically appropriated to carry out this section.

15 USC 717m note

SEC. 26. STUDY AND REPORT ON NATURAL GAS PIPELINE AND STORAGE FACILITIES IN NEW ENGLAND.

(a) STUDY.—The Federal Energy Regulatory Commission, in consultation with the Department of Energy, shall conduct a study on the natural gas pipeline transmission network in New England and natural gas storage facilities associated with that network.

(b) CONSIDERATION.—In carrying out the study, the Commission shall consider the ability of natural gas pipeline and storage facilities in New England to meet current and projected demand by gas-fired power generation plants and other consumers.

Deadline.

(c) REPORT.—Not later than 1 year after the date of enactment of this Act, the Federal Energy Regulatory Commission shall prepare and submit to the Committee on Energy and Natural Resources of the Senate and the Committee on Energy and Commerce of the House of Representatives a report containing the results of the study conducted under subsection (a), including recommendations for addressing potential natural gas transmission and storage capacity problems in New England.

Approved December 17, 2002.

LEGISLATIVE HISTORY—H.R. 3609 (S. 235)

HOUSE REPORTS: No. 107–605, Pt 1 (Comm. on Transportation and Infrastructure) and Pt. 2 (Comm. on Energy and Commerce).

CONGRESSIONAL RECORD, Vol 148 (2002):

July 23, considered and passed House.

Nov 13, considered and passed Senate, amended.

Nov. 14, House concurred in Senate amendment.

O

DISCOVERY REQUEST NO. 13:

Provide all leak reports and emergency main replacement incidents and describe the costs over the past 5 years involved directly attributable to "Bare Steel" and Cast Iron Mains Detail the costs incurred in repairing mains due to these incidents

Response:

Chattanooga Gas Company, Inc. ("CGC" or the "Company") objects to this interrogatory on the grounds that it is overly broad and burdensome. Subject to and without waiving the foregoing objection, the Company provides the following response:

CGC does not retain in its data base the number of leak reports for years ended before December 2001. However, during the three years ended December 31, 2003 CGC received 11,298 leak reports from customers Such reports, however, in many cases, did not necessarily result in actual leaks being located. In addition, all leaks that were located as a result of such reports were not in mains and in many cases were not even on the Company's piping. In addition such leaks on Company mains that were located as a result of such leak reports were not tracked by the type of mains, (bare steel, cast iron, coated steel, or plastic.)

Over the past 5 years, CGC did repair 220 corrosion leaks. These repairs were not tracked by the type of mains (bare steel, cast iron, coated steel, or plastic) . As a result, the cost associated with "emergency" repairs to bare steel and cast iron is not identifiable on the Company's books. In addition, the "emergency main replacement incidents" were recorded as maintenance expense repairs, not completed as capital projects. Thus, the identification of the details of the cost for the "emergency" main replacements would require the manual review of each of the approximately 30,000 distribution works orders completed during the last 5 years to identify which work orders were for the repair of corrosion leaks and to determine the related cost.

Discovery Request No. 14

On p. 4 of Mr. Lonn's testimony he states, "The replacement will result in not having to repair an ever increasing number of leaks related to bare steel and cast iron pipeline." If this is so, explain why an aggressive replacement program was not cost beneficial and therefore was not implemented by management in prior years.

Response:

Mr. Lonn's quote on page 4 was in no way related to the economics of the timing of the start of a program, but rather was a general safety based statement made to indicate that since neither bare steel nor cast iron pipe can be cathodically protected, as the pipe continues to corrode or graphitize, the frequency of leaks will increase as the remaining pipe wall thins or softens.

Additionally, the premise of the question is incorrect in its statement that an aggressive replacement program had not previously been instituted by the Company. Since 1990 the Company has reduced the mileage of bare steel and cast iron main by over 150 miles. However, the remaining sections of pipe continue to age and the issue of an increasing number of leaks and the public safety becomes more significant. As the plant ages beyond its effective life, the benefits of a rational and comprehensive plan for replacement of the remaining pipe become much more important. The vast majority of remaining cast iron pipe in question was installed between 1904 and 1946 which means that it is between 58 and 100 years old and the bare steel pipe installed between 1915 and 1966 is between 89 and 38 years old. When the Tennessee Regulatory Authority approved Chattanooga Gas Company's current depreciation rates, it adopted a 55 year life cycle for Company's mains which includes protected steel in addition to the cast iron and bare steel that is to be replaced. The objective of the replacement program in this case is to implement a systematic program to complete the replacement of these aging facilities over the next ten years before the number of leaks become acute in order to ensure that reliable service can continue to be provided and that public safety is not jeopardized.

Discovery Request No. 15

Identify each person whom you expect to call as an expert witness at any hearing in this docket, and for each such expert witness:
(A) Identify the field in which the witness is to be offered as an expert;

Response:

Chattanooga Gas Company, Inc. objects to this interrogatory on the grounds that this requested data was previously provided in this docket, and the request is overly broad and burdensome. The interrogatory goes well beyond the discovery permitted pursuant to Tenn. R Civ. P § 26.02(4)(A)(i). Subject to and without waiving the foregoing objection, the Company provides the following response:

Steve Lindsey – overview of Chattanooga Gas Company's (CGC) operations and various proposals requested in this docket

Philip G. Buchanan – general service rate design, calculation of test period and attrition period revenues, rates to recover attrition period revenue requirement

Michael J. Morley – cost of service, rate base, capital structure and cost of debt financing.

Richard R Lonn – Bare Steel and Cast Iron Pipeline Replacement tracker and CGC's pipeline integrity program.

Dr. Roger A. Morin – cost of equity

(B) provide complete background information, including the expert's current employer as well as his or her educational, professional and employment history, and qualifications within the field in which the witness is expected to testify, and identify all publications written or presentations presented in whole or in part by the witness;

Response:
Chattanooga Gas Company, Inc. objects to this interrogatory on the grounds that the requested data was previously provided in this docket, and is overly broad and burdensome. The interrogatory goes well beyond the discovery permitted pursuant to Tenn. R. Civ. P § 26.02(4)(A)(i) Subject to and without waiving the foregoing objection, the Company provides the following response:

Steve Lindsey - Please refer to the prefiled testimony of Steve Lindsey, page 1, lines 18 through 26.

Philip G. Buchanan – Please refer to the Prefiled Testimony of Philip G. Buchanan, page 1, lines 16 through 23.

Michael J. Morley – Please refer to CAPD 15 (B) Attachment A, included with this response.

Richard R. Lonn –Please refer to Attachment A included in the Prefiled Testimony of Richard R. Lonn.

Dr. Roger A Morin – Please refer to the Prefiled Testimony of Dr. Roger A. Morin, page 1, lines 14 through 23, page 2, lines 1 through 14 and Exhibit No RAM-1.

(C) **provide the grounds (including without limitation any factual basis), for the opinions to which the witness is expected to testify, and provide a summary of the grounds for each such opinion;**

Response.

Chattanooga Gas Company, Inc. objects to this interrogatory on the grounds that this requested data was previously provided in this docket, and is overly broad and burdensome The interrogatory goes well beyond the discovery permitted pursuant to Tenn. R. Civ. P § 26 02(4)(A)(i). Subject to and without waiving the foregoing objection, the Company provides the following response:

Steve Lindsey - Please refer to the prefiled testimony of Steve Lindsey.

Philip G. Buchanan – Please refer to the prefiled Testimony of Philip G. Buchanan.

Michael J. Morley – Please refer to the Prefiled Testimony of Michael J Morley.

Richard R Lonn –Please refer to the Prefiled Testimony of Richard R. Lonn.

Dr. Roger A Morin – Please refer to the Prefiled Testimony of Dr. Roger A. Morin.

(D) **identify any matter in which the expert has testified (through deposition or otherwise), by specifying the name, docket number and forum of each**

case, the dates of the prior testimony and the subject of the prior testimony, and identify the transcripts of any such testimony;

Response:

Philip G. Buchanan – Earnings Review To Establish Just and Reasonable Rates For Atlanta Gas Light Company, Docket Number 14311-U before the Georgia Public Service Commission, Deposition taken by GPSC Staff on Nov 7, 2001 regarding the forecast of Company revenues in the forward-looking test year.

Richard R Lonn-Cost Allocation Methodology for Lost and Unaccounted for Natural Gas, Docket 15527-U before the Georgia Public Service Commission, July 2002.

Dr Roger A. Morin – Please refer to Exhibit No. RAM-1 to the Prefiled Testimony of Dr. Roger A. Morin.

Mr. Lindsey and Mr. Morley have not previously testified in regulatory proceedings.

(E) **identify the terms of the retention or engagement of each expert including but not limited to the terms of any retention or engagement letters or agreements relating to his/her engagement, testimony, and opinions as well as the compensation to be paid for the testimony and opinions;**

Response:

Steve Lindsey - Full-time employee of Chattanooga Gas Company

Philip G Buchanan – Full-time employee of AGL Services Company

Michael J. Morley – Full-time employee of AGL Services Company

Richard R Lonn – Full-time employee of AGL Services Company

Dr. Roger A. Morin – See CAPD Discovery #15(E) Attachment A. This attachment is marked confidential and is being filed under seal pursuant to the protective order issued in this docket.

(F) identify all documents or things shown to, delivered to, received from, relied upon, or prepared by any expert witness, which are related to the witness(es)' expected testimony in this case, whether or not such documents are supportive of such testimony, including without limitation all documents or things provided to that expert for review in connection with testimony and opinions; and

Response

Chattanooga Gas Company objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving the foregoing objection, the Company provides the following response:

In their positions with Chattanooga Gas Company and AGL Services Company, Mr. Lindsey, Mr. Morley, Mr. Lonn, and Mr. Buchanan routinely view various documents related to Chattanooga Gas Company's operations including its investment in plant, its revenue, its operating expenses, and other costs. Any of these records or documents could, at the extreme, be classified as being "related" to these witnesses' testimony. In the normal course of business these witnesses do not retain records of the documents which they view. In addition, the number of such documents and records that these witnesses would have routinely viewed while performing their daily duties during the time that this case was being prepares is voluminous and unduly burdensome to produce.

Documents provided to Dr. Morin by the company include the AGL Resources, Inc. annual report (a copy of which was previously filed in response to Minimum Filing Guideline # 17), copies of the pre-filed testimony of CAPD witness Steve Brown, and Nashville Gas witness Donald A. Murry in Docket 03-00313. This testimony is a matter of public record on file at the TRA in Docket 03-00313. (As a party to that proceeding, the CAPD should have in its possession copies of this testimony.) In addition Dr. Morin was provided credit rating data that is included as CAPD 15 (F) Attachment A.

In addition to the documents provided by the Company, Dr. Morin consulted the following documents and data sources: AGL Resources, Inc. SEC 10-K form, available from the Edgar SEC Web site; AGL Resources, Inc. annual report, available on AGL Resources, Inc. Web site; Moody's Credit Rating report available from Moody's Web site by paid subscription; Moody's Public Utility Manual, 2002 edition, available from most public and/or university libraries; Analyst' growth forecast data were taken directly from the Zacks Investment Research Web site, available by paid commercial subscription only; Value Line's "Investment Survey for Windows" CD-ROM, is proprietary and available by paid commercial subscription only. Arrangements can be made to provide the CD-ROM at the Company's offices; Data sources for Exhibits RAM-2 to RAM-9 are listed in the footnotes and are largely from the Value Line Investments Survey for

Windows CD-ROM available by paid commercial subscription only; In reference to the allowed Risk Premium Analysis, the annual allowed ROE data was taken from Regulatory Research Associates, Inc.'s ("*Regulatory Focus*", Regulatory Study) comprehensive survey of ROE decisions by regulators over the period 1994-2003 for electric utilities available by paid subscription only: Relevant sections from the Ibbotson Associates Study *Stocks, Bonds, Bills, and Inflation, 2003 Yearbook* compilation of historical returns and from Value Line's April 2003 "Selection and Opinion" yield data were consulted by Dr. Morin. There are no additional work papers See exhibits in the testimony and the data sources cited a the end of each exhibit.

(G) **identify any exhibits to be used as a summary of or support for the testimony or opinions provided by the expert.**

See prefiled testimony previously filed in this proceedings.

MICHAEL J. MORLEY

Educational Background and Professional Experience

Mr. Michael J. Morley, as Director, Financial Accounting of AGL Resources Inc. (AGLR) and as and an employee of AGLR's wholly-owned subsidiary, AGL Services Company, has responsibility the management of the general ledger, including plant and gas accounting, for AGLR and most of its subsidiaries. This primarily involves management of the day to day accounting transactions that impact the general ledger as well as management of AGLR and Subsidiaries' month end and year end close processes.

Mr. Morley received a B.B.A. from the University of Georgia in June 2001 with a major in accounting.

The following is a summary and timeline of Mr. Morley's professional experience:

- **AGL Resources Inc., Atlanta, Georgia**
  - Director, Financial Accounting, January 2002 to present
  - Manager of Financial Accountıng, September 2000 – January 2002
- **Nevins Marketing Group, Inc., Atlanta, Georgia**
  - Controller, July 1997 – May 2000
- **Moore Colson and Company, P.C.**
  - Senior Auditor, January 1993 to July 1997
  - Staff Auditor, June 1991 to December 1992

CAPD
#15(F)
Attachment A

<HELP> for explanation, <MENU> for similar functions.
Enter # <GO> for historical ratings.

P235 Equity **CRPR**

Related Functions | Company Tree Ratings | CREDIT PROFILE

AGL Resources Inc

Page 1/1

	MOODY'S	
1)	Outlook	STABLE
2)	JR Subordinated Debt	Baa2
	STANDARD & POOR'S	
3)	Outlook	STABLE
4)	LT Foreign Issuer Credit	A-
5)	LT Local Issuer Credit	A-
6)	ST Foreign Issuer Credit	A-2
7)	ST Local Issuer Credit	A-2
	FITCH	
8)	Outlook	STABLE
9)	Senior Unsecured Debt	A-
10)	Short Term	F2

<HELP> for explanation, <MENU> for similar functions. P235 Equity **CRPR**
Enter # <GO> for historical ratings.

Related Functions | Company Tree Ratings | CREDIT PROFILE

AGL Resources Inc Page 1/1

MOODY'S

1)	Outlook	STABLE
2)	JR Subordinated Debt	Baa2

STANDARD & POOR'S

3)	Outlook	STABLE
4)	LT Foreign Issuer Credit	A-
5)	LT Local Issuer Credit	A-
6)	ST Foreign Issuer Credit	A-2
7)	ST Local Issuer Credit	A-2

FITCH

8)	Outlook	STABLE
9)	Senior Unsecured Debt	A-
10)	Short Term	F2

<HELP> for explanation, <MENU> for similar functions. P235 Corp **CRPR**
Enter # <GO> for historical ratings.

Related Functions · Company Tree Ratings · CREDIT PROFILE

AGL Capital Corp Page 1/1

Select 'Company Tree Ratings' above for related companies

MOODY'S

1) ATG 7 ⅛ 01/14/11	Baa1
2) Outlook	STABLE
3) Senior Unsecured Debt	Baa1
4) Short Term	P-2

STANDARD & POOR'S

5) ATG 7 ⅛ 01/14/11	BBB+

FITCH

6) ATG 7 ⅛ 01/14/11	A-
7) Outlook	STABLE
8) Senior Unsecured Debt	A-
9) Short Term	F2

<HELP> for explanation, <MENU> for similar functions. N236 Corp **CRPR**
Enter # <GO> for historical ratings.

Related Functions · Company Tree Ratings · CREDIT PROFILE

AGL Capital Trust I Page 1/1

Select 'Company Tree Ratings' above for related companies

MOODY'S	
1) ATG 8.17 06/01/37	Baa2
2) Preferred Stock	Baa2
STANDARD & POOR'S	
3) ATG 8.17 06/01/37	BBB
FITCH	
4) ATG 8.17 06/01/37	BBB+
5) Outlook	STABLE
6) Preferred Stock	BBB+

STANDARD
&POOR'S

c: Drew
[redacted]

Corporate & Government Ratings
55 Water Street
New York, NY 10041-0003

September 25, 2003

Mr. Richard T. O'Brien
Senior Vice President and Chief Financial Officer
AGL Resources Inc.
P.O. Box 4569
817 West Peachtree Street, N.W.
Atlanta, GA 30308

Re: **<u>AGL Resources Inc.</u>**
<u>$1,000,000,000 Universal Shelf Registration</u>

Dear Mr. O'Brien:

Pursuant to your request for a Standard & Poor's rating on the above-referenced shelf registration, we have reviewed the information submitted to us and, subject to the enclosed *Terms and Conditions*, have assigned a preliminary rating of "BBB+ Debt Securities / BBB Subordinated Debentures / BBB Preferred Stock". A final rating will be assigned to each drawdown only after Standard & Poor's reviews the terms.

The rating is not investment, financial, or other advice and you should not and cannot rely upon the rating as such. The rating is based on information supplied to us by you or by your agents but does not represent an audit. We undertake no duty of due diligence or independent verification of any information. The assignment of a rating does not create a fiduciary relationship between us and you or between us and other recipients of the rating. We have not consented to and will not consent to being named an "expert" under the applicable securities laws, including without limitation, Section 7 of the U.S. Securities Act of 1933. The rating is not a "market rating" nor is it a recommendation to buy, hold, or sell the obligations.

This letter constitutes Standard & Poor's permission to you to disseminate the above-assigned rating to interested parties. Standard & Poor's reserves the right to inform its own clients, subscribers, and the public of the rating.

Standard & Poor's relies on the issuer and its counsel, accountants, and other experts for the accuracy and completeness of the information submitted in connection with the rating. This rating is based on financial information and documents we received prior to the issuance of this letter. Standard & Poor's assumes that the documents you have provided to us are final. If any subsequent changes were made in the final documents, you must notify us of such changes by sending us the revised final documents with the changes clearly marked.

Discovery Request No. 20:

Provide details and copies of the "replacement program" over the past 10 years for comparable footage and cost of mains replaced referred to in Mr. Morley's testimony. Compare the footage of pipeline replaced (actual) to "footage budgeted for pipeline replacement."

Response:

Chattanooga Gas Company, objects to this request because it is vague and cannot be addressed as worded. Mr. Morley did not refer to a "replacement program" over the past 10 years in his pre-filed testimony. Subject to and without waiving the foregoing objection, the Company provides the following response:

Mr. Morley's only references to a replacement program are to the proposed pipeline program on page 17 of his pre-filed testimony:

Q. Did the average rate base change between the test period and the attrition period"

A. Yes. The average rate base increased approximately $2.6 million as follows:

1. The working capital requirement increased approximately $0.9 million, primarily due to an increase in the average balance of stored gas inventory, offset by a decrease in cash requirements and other accounts receivable.
2. <u>The net plant balance increased approximately $3.1 million, primarily due to the bare steel/cast iron pipeline replacement program, improvements to the Company's LNG facility and planned expansion of the Company's system.</u>
3. The above two increases were offset partly by a $1.3 million in deferred income taxes.

Q. What will be the impact to the rate base and the Company's base revenue requirement if the <u>proposed pipeline replacement program</u> is approved?

A. The average rate base will decrease by approximately $2.2 million, and the revenue requirement will decrease by approximately $359,000 if the Company is allowed to recover these costs through the proposed rider.

While Mr. Morley did not address a historic pipeline replacement program, and without waiving any of its rights, CGC is providing in attached CAPD 20-1 budget to actual comparisons for main replacements for 1999-2003. The information prior to 1999 is not readily available.

Actual to Budget Comparison
Main Replacement Programs
1999 - 2003

Budget Year	Description	Total	Proposed Budget	Actual footage	Proposed Footage	PROJECT TYPE	Work Performed by
1999	788250-8000 Blackwell St	$ 1,117 43	$ 5,018 00	195	193	Renewal	Outside Contractor
2001	8000 - EAST ST RENEWAL	$ 152,261 67	$ 121,482 00	6923	6595	Renewal	Outside Contractor
2001	8000 - CREWDSON ST RENEWAL	$ 80,930 13	$ 108,080 00	3925	3945	Renewal	Outside Contractor
2001	8000 - FORTWOOD ST RENEWAL	$ 210,401 99	$ 237,126 00	8468	8823	Renewal	Outside Contractor
2001	8000 - LONG ST RENEWAL	$ 132,758 94	$ 182,705 00	6570	7725	Renewal	Outside Contractor
2001	8000 - Fairleigh St Renewal	$ 7,383 06	$ 5,245 00	164	180	Renewal	Outside Contractor
2001	8000 - N Willow St Project	$ 585,810 11	$ 367,842 00	12965	13019	Renewal	Outside Contractor
2001	8000 - South Kelly Street Proj	$ 463,878 85	$ 296,848 00	11913	11717	Renewal	Outside Contractor
2001	8000 - Montview Dr Project	$ 380,371 53	$ 317,848 00	12001	11932	Renewal	Outside Contractor
2001	8000 - Duncan Ave Renewal	$ 836,972 70	$ 547,332 00	22436	23935	Renewal	Outside Contractor
2001	8000-E 27TH STREET RENEWAL	$ 1,078 82	$ 1,801 00	76	98	Renewal	Outside Contractor
2002	8000 - Cherry St Renewal	$ 63,118 19	$ 74,041 00	658	713	Renewal	Outside Contractor.
2002	8000 - Dayton Blvd Renewal	$ 9,653 13	$ 9,801 00	1602	1650	Renewal	Company Crew
2002	8000 - PRATER RD RENEWAL	$ 30,782 31	$ 40,320 00	1445	1344	Renewal	Outside Contractor

Discovery Request No. 21

Regarding the "Pipeline Replacement Program" in Georgia, provide comparable data (as in # 20 above) covering the "pipeline replacement program" in Georgia.

Response:

From the start of the "Pipeline Replacement Program" in Georgia in 1998 through March of 2004, Atlanta Gas Light Company (AGLC) has spent $250,576,748 in capital costs on main replacement. Through the end of the 5th year of the program, which was September 30th 2003, AGLC had retired over 1,290 miles of main, with up to another 252 scheduled for replacement in year 6.

Discovery Request No. 22:

Provide in detail the number of customers serviced as "walk-ins" for
(a) payment of service,
(b) questions regarding billing or service inquiries, or
(c) other service requested
for the Chattanooga service territory by year for the past ten (10) years.

Response:

(a) Through arrangements with businesses in its service area, Chattanooga Gas Company provides locations where customers may "walk-in" and pay their gas bills. In the normal course of business, Chattanooga Gas Company does not retain the requested data relative to such payments in its Customer Information System beyond two years. The following data is provided by month from May 2002 through April 2004.

Month	Number of Payment Transactions
June 04	3738
May-04	4214
Apr-04	4892
Mar-04	5536
Feb-04	5385
Jan-04	5386
Dec-03	4335
Nov-03	3612
Oct-03	3838
Sep-03	3517
Aug-03	3645
Jul-03	3974
Jun-03	4414
May-03	5950
Apr-03	6384
Mar-03	6934
Feb-03	6910
Jan-03	6635
Dec-02	4868
Nov-02	4105
Oct-02	3792
Sep-02	3449

Aug-02	3887
Jul-02	4122
Jun-02	4312
May-02	5088
Apr-02 (partial)	874

(b) questions regarding billing or service inquiries, or

Response:

Chattanooga Gas Company has not tracked the requested data.

(c) other service requested

Response:

Chattanooga Gas Company has not tracked the requested data.

Discovery Request No. 23

Identify the number of customer bills collected by outside collection agents (by year) for the past ten (10) years.

Response:

CGC does not have records of the number of collections by outside collection agents prior to 1995. The following are the number of accounts with collection agency transactions by year.

Year	Number of Accounts With Collection Agency Transactions
1995	178
1996	390
1997	495
1998	447
1999	355
2000	309
2001	287
2002	381
2003	382

Discovery Request No. 24

Provide any and all requests for any additional service sites and all complaints about or relating to availability of customer service for the past five years.

Response:

Chattanooga Gas Company could find no complaints related to the availability of customer service or requests for additional service sites.

Discovery Request No. 26

Provide the data for the following categories of customer service:

(A) **Customer Service by year (for years 1998 - 2003):**

1. Number of Calls Received (percent answered);
2. Average Answer Time (in minutes);
3. Length of Call (in minutes);
4. After Call Processing Time (in percent);
5. Number of Walk-ins;
6. Customer Call Backs;
7. Supervisor Referrals; and
8. Cash Transactions Processed (Chattanooga).

Response (A) 1. The Number of Calls Received by year:

1998	103,173
1999	99,466
2000	97,171
2001	92,766
2002	88,111
2003	101,993

All calls received were answered.

(A) 2. Average Answer Time (in minutes):

The average answer time was not separately tracked for Chattanooga Gas Company prior to 2001. The answer time is tracked in minutes and seconds.

1998	Information not available
1999	Information not available
2000	Information not available
2001	1:29
2002	:58
2003	:30

(A) 3. Length of call (in minutes):

The average length of call was not separately tracked for Chattanooga Gas Company prior to 2001. The call length is tracked in minutes and seconds.

1998	Information not available
1999	Information not available
2000	Information not available
2001	5:00
2002	4:16
2003	4:31

(A) 4. After call processing time (in percent):

After call processing time is not tracked separately. The after call time is included in the length of call provided in Item 26(A)3.

(A) 5. Number of walk-ins

In the normal course of business the requested information is retained in the Customer Information System for two years. Therefore the data prior to May 2002 is not available.

1998	Information not available
1999	Information not available
2000	Information not available
2001	Information not available
2002	May 2002 – December 2002 - 33,623
2003	60,148

(A) 6. Customer call backs
Customer call backs were not tracked prior to 2004.

(A) 7. Supervisor referrals
Supervisor referrals were not tracked prior to 2004.

(A) 8. Cash Transactions Processed (Chattanooga) (number)

In the normal course of business the requested information is retained in the Customer Information System for two years. Therefore the data prior to May 2002 is not available.

1998 Information not available
1999 Information not available
2000 Information not available
2001 Information not available
2002 May 2002 – December 2002 419,367
2003 665,164

(B) **Meter Services by year (for years 1998 - 2003):**

1. **Number of Meters Read;**
2. **Risers Inspected;**
3. **Estimated Readings;**
4. **Percent Estimated;**
5. **Skips;**
6. **Re-reads;**
7. **Door Tags; and**
8. **DNPs Worked.**

Response:

B(1) Meters Read

Statistics nor retained prior to 2000.

1998	Not Available
1999	Not Available
2000	689,904
2001	712,435
2002	775,881
2003	741,104

B(2) Risers Inspected

Statistics nor retained prior to 2001.

	Not Available
	Not Available
	Not Available
2001	13,106
2002	17,983

B(3) Estimated Readings

Statistics nor retained prior to 2000

1998	Not Available
1999	Not Available
2000	16,080
2001	3,796
2002	5,262
2003	2,650

B(4) Percent of Estimates

Statistics nor retained prior to 2000

1998	Not Available
1999	Not Available
2000	2.3%
2001	0.5%
2002	0.7%
2003	0.4%

B(5) Skips;

Statistics nor retained prior to 2000

1998	Not Available
1999	Not Available
2000	5,355
2001	3.739
2002	3,835
2003	2,117

B(6) Re-reads;

Statistics nor retained prior to 2000

1998	Not Available
1999	Not Available
2000	1,056
2001	1,896
2002	1,440
2003	1,160

B(7) Door Tags

Chattanooga Gas Company does not track the number of door tags left. However, it is the Company's policy to leave a door tag whenever we go on premise to complete a work order but can not due to the customer not being at home or not having left a key. A door tag is left notifying the customer of the visit and directing the customer to call to reschedule if work is still needed. Such work orders are coded as CGI (Could not Get In). Such CGI orders were not tracked for 1998-2000. The following are the numbers of CGI orders for 2001, 2002, and 2003.

Statistics nor retained prior to 2000

1998	Information not available
1999	Information not available
2000	Information not available
2001	1,395
2002	2,129
2003	2,248

B(8) SNOPs Worked

1998	Information not available
1999	Information not available
2000	2,994
2001	3,748
2002	4,237
2003	4,744

(C) Service Department (by month for years 2001 - 2003):

1. Orders Worked;
2. Appointment Orders;
3. Appointments Missed;
4. Emergency Orders;
5. Emergency Response Time (minutes); and
6. Meters Set.

Response:

C(1) Orders Worked

2001	30,240
2002	31,928
2003	32,753

C(2) Appointment Orders

2001	13,837
2002	12,720
2003	14,359

C(3) Appointment Missed

2001	1,918
2002	1,216
2003	1,207

C(4) Emergency Orders

2001	3,880
2002	3,632
2003	3,766

C(5) Emergency Response Time (minutes)

2001	32.92 Min
2002	30.03 Min
2003	28.35 Min

C(6) Meters Set.

2001	1,858
2002	2,032
2003	1,850

Orders count does not include non account leak and CGC soon as possible (SOP) orders.

(D) Construction Department (for years 1998 - 2003):

1. **Service Orders Received;**
2. **Service Orders Installed;**
3. **Backlog (Weeks);**
4. **Damages;**
5. **Service Renewal/Relocate;**
6. **Services Retired; and**
7. **Survey Leaks.**

Response:

(D) 1 Service Orders Received

1998 – 1,341
1999 – 870
2000 – 1,243
2001 – 1,050
2002 – 1,044
2003 – 2,669

(D) 2. Service Orders Installed

1998 – 1,341
1999 – 870
2000 – 1,243
2001 – 1,050
2002 – 1,044
2003 – 1,031

(D) 3. Backlog (Weeks)

In the normal course of business the Company does not retain the backlog data from previous periods as requested and therefore it can not be provided.

(D)4. The number of 3rd party damages by year:

1998 – 477
1999 – 475
2000 – 108
2001 – 286
2002 – 172
2003 – 208

(D)5. Service Renewal/Relocate by year;

1998 – 383
1999 – 16
2000 – 90
2001 – 208
2002 – 238
2003 – 163

(D)6. Services Retired by year

1998 – 565
1999 – 204
2000 – 393
2001 – 542
2002 – 520
2003 – 326

(D) 7. Survey Leaks by year

1998 – 288
1999 – 329
2000 – 500
2001 – 656
2002 – 1,476
2003 – 575

Discovery Request No. 33

Since Rick Lonn's "PRP" proposal is very similar to the Georgia proposal, explain the "verification process" or audits conducted by various departments of the Georgia Public Service Commission; i.e., provide a narrative of how the verification process will work, including how replacement projects are to be distinguished from new work; how the bid process will work; and how the auditing procedure of the rate rider adjustments to the billing process will work.

Response:

Verification Process

Atlanta Gas Light Company utilizes "Project Type" to distinguish all types of projects, including, but not limited to, new business, business support and other projects. For PRP projects, a project type of "MANDA" is used to segregate the costs of actually replacing the pipe from all other project types. Additionally, "activity type" is a field utilized on each cost transaction to further segregate PRP costs from non-PRP project costs. These activity types are as follows:

- "BCRPL" - Cast iron replacement
- "BCREM" - Cast iron removal
- "BSRPL" - Bare steel replacement
- "BSREM" - Bare steel removal

The "BCREM" and "BSREM" activity types are used to segregate removal costs associated with the PRP from removal cost from all other project types.

Bid Process

In the normal course of business, Atlanta Gas Light Company (AGLC) awards the work to the lowest bidder whose proposal meets the criteria in the request for bids.

Audit Procedure of the Rate Adjustments

To verify the costs recovered and to be recovered through the PRP Rider, the Georgia Public Service Commission (GPSC) Staff conducts quarterly audits of the program during which it selects and reviews detailed supporting documentation for charges subject to recovery through the PRP Rider. In addition, the GPSC Pipeline Safety Staff conducts random audits of the contractors in the field. Annually, both AGLC and the GPSC staff submit annual reports to summarize the work and costs of the program of the previous year to the GPSC Commissioners

The project and cost tracking, accounting, and bidding process for Chattanooga Gas Company (CGC) will be the same as that utilized by AGLC. It is anticipated that similar reporting procedures will also be adopted for CGC. The auditing and review procedures to be followed by the TRA Staff will be established by the TRA.

Discovery Request No. 34

On p. 5, line 1 of Mr. Lonn's testimony is a reference to his Schedule 1 detailing the cost of main replacement increasing in cost from $50.94 to $70.88 per foot. Explain this increase in cost and compare with main replacement cost per foot for pipeline replacement projects in Georgia.

Response:

Costs for the pipeline replacement program are estimated using current pricing, diameter size of replacement pipe and historic inflationary factors. These factors are included in the average cost per foot over the ten years of the proposed program. These same factors were used to calculate the estimates for the Georgia pipeline replacement program over a 10 year period.

Please refer to attachment CAPD 34-1 for an explanation of the annual increase in the average cost per foot for Chattanooga Gas Company as well as the estimated costs for the Georgia program for 2004 – 2008.

Chattanooga Gas Company
Expenditures - Bare Steel and Cast Iron Pipeline Replacement Program

	FY	Total (feet)	Total (miles)	Average $/ft	Total Install Capital$	Total Retired Expenditures	Total Annual Expenditure	
	FY 2004	47520	9 00	$50 94	$2,420,489	$104,799 00	$2,525,288	Dollars based on current pricing and small diameter pipe
	FY 2005	58080	11 00	$51 65	$3,000,000	$200,000 00	$3,200,000	Dollars based on current pricing and small diameter pipe, escalator of 1/2 the current inflation rate
(A)	FY 2006	52800	10 00	$57 17	$3,018,312	$446,710 18	$3,465,022	Dollars based on current pricing and small and large diameter pipe, escalator of current inflation rate (3%)
	FY 2007	52800	10 00	$60 59	$3,199,411	$473,512 79	$3,672,924	Dollars based on current pricing and small and large diameter pipe, escalator of current inflation rate (3%)
	FY 2008	52800	10 00	$62 31	$3,289,960	$486,914 09	$3,776,874	Inflation rate escalator
	FY 2009	52800	10 00	$64 02	$3,380,509	$500,315 40	$3,880,825	Inflation rate escalator
	FY 2010	52800	10 00	$65 74	$3,471,059	$513,716 70	$3,984,776	Inflation rate escalator
	FY 2011	52800	10 00	$67 45	$3,561,608	$527,118 01	$4,088,726	Inflation rate escalator
	FY 2012	52800	10 00	$69 17	$3,652,158	$540,519 31	$4,192,677	Inflation rate escalator
	FY 2013	52800	10 00	$70 88	$3,742,707	$553,920 62	$4,296,627	Inflation rate escalator
	FY 2014							
	Total	528000	100		$32,736,213	$4,347,526	$37,083,739	

(A) Exhibit RRL-1, Schedule 1 of the prepared direct testimony of Richard Lonn provided an average cost per foot of $55 50 The above schedule has been corrected to include an average cost per foot of $57 17 The change in average cost per foot does not change the total estimated capital expenditures for FY 2006 nor the estimated capital expenditures for the ten year program

Atlanta Gas Light Company
Expenditures - Bare Steel and Cast Iron Pipeline Replacement Program

FY	Total (feet)	Total (miles)	Average $/ft	Total Install Capital$	Total Retired Expenditures	Total Annual Expenditure
FY 2004	1,298,880	246	$62 15	$80,729,059	$9,687,487	$90,416,547
FY 2005	1,452,000	275	$55 17	$80,102,652	$9,612,318	$89,714,971
FY 2006	1,188,000	225	$67 42	$80,094,544	$9,611,345	$89,705,889
FY 2007	1,322,511	250	$61 20	$80,942,871	$9,713,144	$90,656,015
FY 2008	1,184,850	224	$67 40	$79,864,038	$9,583,685	$89,447,722
Total	6,446,241	1,481		$447,055,876	$53,646,705	$500,702,581

Discovery Request No. 35

Explain the reasons for implementing the "Pipeline Replacement Plan" before the "pipeline integrity assessment" is completed.

Response:

The Pipeline Replacement Program (PRP) and "pipeline integrity assessment" are two separate and unrelated initiatives. The PRP is related to replacing bare steel and cast iron facilities, whereas pipeline integrity is related to ensuring the integrity of the Company's transmission pipelines which are its largest diameter high pressure pipelines, so their timing is unrelated.

Discovery Request No. 36

At p. 9 of Mr. Buchannan's testimony, he discusses the reasoning for increasing the re-connection fee and seasonal reconnection fee to $50.00 (Testimony p. 9). One of the reasons given was that seasonal reconnects increase overtime costs. How much of a reduction in overtime costs does CGC anticipate as a result of the increase in this rate?

Response:

CGC does not propose the increase in the seasonal reconnection fee as a deterrent to disconnecting and reconnecting service at a premise seasonally. Therefore, CGC does not anticipate a material change in overtime costs associated with seasonal reconnection. CGC proposes the increase in the seasonal reconnect fee to better align the recovery of costs incurred by seasonal disconnection and reconnection of service with the customers who receive the reconnection service. Although the proposed charge of $50 does not entirely recover the cost of reconnection, it mitigates the contribution, through base rates, from other customers who do not elect to receive the seasonal reconnection service.